American Law and Jurisprudence on Fracing—2012

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Table of Contents

American Law and Jurisprudence on Fracing

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Introduction

The substantial growth of domestic unconventional shale resources in recent years has largely been a result of the increase in the use of hydraulic fracturing. The concept and practice of fracing was in existence in the 1940s in West Texas in vertical well bores, designed to create artificial permeability in an oil-bearing formation consisting of a thick geological deposit with little or no permeability. In the past decade, hydraulic fracturing has unlocked oil and natural gas deposits in deep shale formations around the country.

Hydraulic fracturing is generally viewed as a completion technique that is a practical necessity to promote development of unconventional "tight" shale reservoirs, particularly gas-shale. Hydraulic fracturing entails treating water, oil, or gas wells to stimulate more production than otherwise would have been achieved using standard drilling and production techniques. This report deals with hydraulic fracturing and the legal and technical issues associated with it.

This report first covers what hydraulic fracturing is and why it is done. It identifies the current location of the largest shale fields where hydraulic fracturing is common and the effect of hydraulic fracturing on domestic production. It then covers the environmental issues, focusing on the anecdotal and evidentiary call and response among environmental groups, regulators, landowners, and producers. It then discusses how traditional oil and gas jurisprudence impacts hydraulic fracturing, emphasizing both surface versus mineral estate issues and disputes that arise between two adjoining mineral owners. Finally, it addresses developments in technology and processes that promise to reduce the environmental footprint of the hydraulic fracturing while promoting its efficiencies and economies. These developments are gaining in the immediacy of their need with the increasing scarcity of water resources, especially in states plagued by drought, as well as populist pressures and the specter of the EPA yearning for expansion of its regulatory authority.

We examine the regulatory frameworks currently in place in sixteen (16) states where hydraulic fracturing is common (or at least known). This state-level analysis is made with an eye towards regulations specific to hydraulic fractioning and the fluids used, as well as more overarching regulations that include hydraulic fracturing among other exploration and production activities, such as general pollution disposal regulations that cover used hydraulic fracturing fluid as well as other liquid waste from drilling. In several instances, this report describes recent state-level legislation and associated regulations, as well as bills under consideration, and important opinions from state courts. We also consider hydraulic fracturing on semi-sovereign tribal land and in Canada.

Finally, this report analyzes the current and contemplated laws and regulations governing hydraulic fracturing on the federal level. In particular, it discusses the history of the litigation and legislative efforts challenging the current federal exception enjoyed by hydraulic fracturing. It also highlights the friction between state and federal oversight.

Hydraulic Fracturing—an Overview

Most people are familiar with the "gusher" well where reservoir pressure underground pushes oil up the wellbore. Oil and gas are harder to extract from "tight" rock formations, which do not allow passage of oil and gas through and up a well. Although such formations, often shale or coal, may be filled with gas or oil, they only allow those fluids to flow along preexisting cracks or "fractures."

Naturally-occurring fracture patterns have long been used to heighten development in otherwise uneconomic formations. One example is the Austin Chalk, a tight fossiliferous chalk and marl formation found in the Gulf Coast region of the United States. The Austin Chalk in Texas and coal seams in Appalachia are marked by zones of natural fractures which trend in a common direction.[1] While the Austin Chalk is often saturated with hydrocarbons, it typically remains uneconomic unless a horizontal borehole intersects a number of the fractures. Therefore, seismic and surficial mapping techniques were developed to find these natural fracture zones and orientations.[2]

The usefulness and application of hydraulic fracturing to horizontal well bores only became apparent with the discovery that "tight" shale formations could be economically developed with hydraulic fracturing techniques—that is, by making *artificial* fractures. Now, instead of relying on natural fractures zones, developers make their own fractures.

Hydraulic fracturing—known colloquially as "fraccing," "fracking" and, in this report, as "fracing"—is a process in which fluid is injected into a well at very high pressures in order to either widen and deepen existing cracks or create new fractures in the tight formation.[3] Generally, the use of fracturing technologies in vertical and horizontal well bores will allow more oil or gas to be produced from wells previously thought dry or in decline. Petroleum companies vary the type of fluid used for fracing depending on the rock type, depth or other factors. The fluids used can include water, water mixed with solvents, or drilling mud. The fluid

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1 *See* Byron R. Kulander and Stuart L. Dean, *Coal-cleat Domains and Domain Boundaries in the Alleghany Plateau of West Virginia*, American Association of Petroleum Geophysicists ("*AAPG*") Bulletin, 1374-1388 (1993), v. 77, no. 8.; *see also* Kevin P. Corbett, David R. Van Alstine and Janell D. Edman, *Stratigraphic Controls on Fracture Distribution in the Austin Chalk: an Example from the First Shot Field, Gonzalez Co., Texas*, 1997 AAPG Hedberg Research Conference.

2 *See e.g.* Ilyas Juzer Najmuddin, Austin Fracture Mapping Using Frequency Data Derived from Seismic Data (2003) (unpublished PhD. dissertation, Texas A&M University) (on file with Texas A&M University Library) *available at* http://repository.tamu.edu/bitstream/handle/1969.1/34/etd-12112002-153843-1.pdf?sequence=1 (last visited May 3, 2010).

3 The American Petroleum Institute ("*API*") maintains a short video of current fracing techniques at http://www.api.org/policy/exploration/hydraulicfracturing/hydraulicfracturing.cfm (last visited April 23, 2010).

is mixed with the "proppant," which is typically sand, ceramic pellets or other small granular material that is carried into the fractures where it remains to prop the crack open thereby allowing the oil or gas to flow.

Fracing is not a new technology. Hydraulic fracing was first tested in 1903 and first used commercially in 1948. By 1988, hydraulic fracturing had been applied to one million wells.[4] It has also been used to enhance production from water wells. Currently, about 35,000 wells per year undergo some measure of hydraulic fracturing and a majority of oil and gas wells have undergone some form and level of fracturing during their productive lifetime.[5] The prevalence of horizontal drilling has also increased the importance of fracing as boreholes can now traverse through a much longer portion of a targeted horizon instead of the interval covered by vertical or slant drilling, making the return to the operator in increased production worth the cost of mobilization of a fleet of fracing equipment. Because fracing can be conducted all along the interval the borehole is in the productive zone, more gas can be drained from each well, meaning one horizontal well can replace multiple vertical wells, cutting back on the surface footprint necessary to exploit the gas assets in a given area.

Drilling and Groundwater Protection

To understand how fracing operations work and the relationship between fracing fluids and groundwater, it is first necessary to understand the fundamentals of how drillers set casing, cement boreholes, and set up a production zone. Fracing fluids are not the first fluids to be introduced to a wellbore during drilling. During drilling operations, drilling fluid is circulated down and around the drill bit and stem connecting the bit to surface—the "drill string"—then out the bottom of the drill string through a hole in the drill bit and back up the space between the drill string and the surrounding rock. The drilling fluid prevents formation fluids from entering into the well bore, keeps the drill bit cool and clean during drilling, carries out drill cuttings (which help mud loggers determine what formation is currently being drilled through), and helps support the hole while drilling is paused and the drilling assembly is brought in and out of the hole. Drilling fluid can be either water, oil or synthetic-based and is generally a mixture of clays, fluid loss control additives, density control additives such as barite, and other fluid-thickeners.[6]

A main goal of any well is to ensure safe production of oil and gas in a way that protects groundwater and heightens production by keeping hydrocarbons inside the well and isolating the productive formations from aquifers and other formations. Sound well design and drilling ensure that no significant leakage will occur between any casing joints and that fluids introduced to the

4 Howard, G.C. and C.R. Fast (editors), Hydraulic Fracturing, Monograph Vol. 2 of the Henry L. Doherty Series, Society of Petroleum Engineers New York, 1970; *also see* "History of Hydraulic Fracturing", Energy In Depth, *available at* http://www.energyindepth.org/in-depth/frac-in-depth/history-of-hf/ (last visited March 29, 2010).

5 Interstate Oil & Gas Compact Commission ("*IOGCC*"), Resolution on Hydraulic Fracturing 09.011, January 2009 Special Meeting, *available at* http://www.iogcc.state.ok.us/2009-resolutions (last visited May 3, 2010). The IOGCC maintains a website devoted to hydraulic fracturing and other issues affecting the domestic oil and gas industry at http://groundwork.iogcc.org/ (last visited May 9, 2010).

6 HOWARD R. WILLIAMS AND CHARLES R. MEYERS, MANUAL OF OIL & GAS TERMS, section '*M*' (2D ED. 2009).

casing string at the surface or produced from the production zone must travel directly from the production zone to the surface inside the wellbore.[7]

Drilling a modern oil and gas well involves placement of tubes of steel, fitted together, into a borehole. These tubes are called "casing" and they are used to seal off the drilling and formation fluids from migrating into groundwater aquifers and to keep the wellbore from caving in.[8] The deeper one goes in the well, the smaller the diameter of the drill stem—complete wells are similar to an extended sea captain's monocular. The first hole to be drilled is for the biggest tube of steel, the conductor pipe. The conductor pipe can also be driven into place, like a structural caisson, by a cable-tool rig. This pipe is followed by (i) the surface casing, (ii) the intermediate casing (if necessary), and (iii) the production-zone casing. Each of these has a progressively smaller diameter.[9] (*See* Figure No. 1, *Source: American Petroleum Institute*)

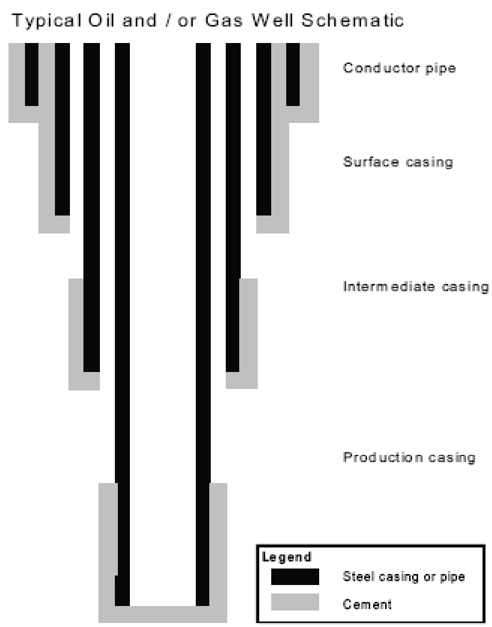

Figure 1—Typical Well Schematic

The conductor pipe keeps out loose sediment at and near the surface and separates the groundwater zones from the drilling fluids. After the conductor pipe is installed and cemented into place, drilling continues and the surface casing is centered into the hole and cemented in place. Like the conductor pipe, the main purposes of the surface casing and cement are to provide stability for the subsequent deep drilling and completion operations and separation of potable groundwater found in near-surface aquifers.[10]

These first and second phases of drilling—constituting the "surface hole" portions of

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[7] *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines 4*, AMERICAN PETROLEUM INSTITUTE (API Guidance Document HF1, First Edition), October, 2009, at 3.

[8] *Manual of Oil and Gas Terms*, Casing 131, 132 (13th ed. 2006).

[9] *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines 4*, *supra* note 7 at 2-4.

[10] *Id.* at 4.

drilling—are often completed with a smaller, cheaper drill rig and are commonly drilled using freshwater-based drilling fluids to prevent groundwater contamination. The surface hole is usually drilled to a predetermined depth established by the deepest occurrence of groundwater resources and can range from a couple hundred feet to 1000 feet deep or more. State regulations dictate the minimal setting depth of surface casing, with nearly all states requiring the surface casing to be set below the deepest freshwater aquifer. Generally, the surface casing is set at least one hundred (100') feet below the deepest potable water encountered while drilling the well or the fresh/salt water boundary in the area, if known.[11]

In addition to the protection of the groundwater provided by the steel casing, the American Petroleum Institute (the "*API*") recommends that the surface casing be entirely cemented to completely isolate freshwater aquifers. This isolates the groundwater zones near the surface from the borehole and the drilling/fracing fluid with several layers of steel augmented by cement. After the casing has been inserted into the hole, it is cemented in place. The cement slurry is pumped into the well just like the drilling fluid, down through the casing and back up into place outside of the casing.[12]

Subsequent to completion of the surface hole and casing, a larger drill rig is typically moved into position and drilling of the "intermediate hole" and the "production hole" is commenced. The intermediate hole is the broad zone of strata encountered between the surface groundwater zones and the area from which production or horizontal drilling will take place. Casing in the intermediate zone provides hole stability and prevents hole collapse from high-pressure zones encountered while drilling to the productive zones. Unlike the surface casing zone, complete cementing of the intermediate hole back to the surface is not usually necessary, but hydrocarbon-bearing zones are generally always cemented. Once the intermediate zone is traversed by drilling, pressure testing is sometimes conducted to determine the maximum pressure that the casing string can withstand, to determine the integrity of previous cement job, and determine the maximum mud weight which can be used for the next casing setting depth.[13]

Finally, the production zone is reached. After the production zone is drilled and logged, if things look promising, production casing is run to the total depth (the "TD") of the well, and the producing formation is sealed off with expanding rings called "packers" and cemented in place. The production casing contains the downhole production equipment. In addition, like the casing in the intermediate zone, the production casing isolates the producing formations from other formations so that the only communication between the surface and the rock is through the perforated production casing. This isolation allows the drillers to recover the initial draw of oil and gas and, subsequently, to target the input of fracing fluids and other stimulation techniques directly into the producing formation without affecting any other formation or aquifer.[14]

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11 *Id.* at 11.

12 *Id.*

13 Apiwat Lorwongngam, The Validity of Leak-Off Test for In Situ Stress Estimation; the Effect of the Bottom of the Borehole (2008) (unpublished M.S. thesis, University of Oklahoma), on file with the University of Oklahoma Library *available at* http://mpge.ou.edu/research/documents/Lorwongngam.pdf (last visited March 28, 2010).

14 *Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines 4*, *supra* note 7 at 12.

The result of this process, if followed with care and thoroughness, is a completed borehole where the freshwater aquifers, are separated from communication with the fluids in the wellbore by two or three layers of steel tubing and one or two layers of impervious cement. The producing formations near the bottom of the hole are typically thousands of feet away from the uphole aquifers and separated by cement and packers.[15]

Fracing Fluids and Operations

Fracing requires a "fracing fluid" to be pumped into the well's production casing at a very high pressure and rate. Therefore, the production casing string and the cement holding it in place must be capable of withstanding the pressure. If the integrity of the production casing is in doubt, a high pressure "frac string" may be used to direct the fracing fluid to the prospective interval. The frac string is removed once operations are complete.[16]

The actual fracing takes place in three phases. The first phase, called the "pad," occurs when the hydraulic fluid is first pumped into the productive zone without any proppant. This is done to instigate the fractures in the rock and to prime the location so that any fluid leakage into immediately adjacent zones are accounted for. The second stage occurs when the proppant is added to the mix. Proppant can be simple sand or man-made materials such as ceramic beads or sintered bauxite. The proppant holds the fractures open, allowing the gas to flow after the fracing fluid is pumped out. Without the proppant, the pressures at depth could largely reseal the fractures, defeating the value of the operation. Finally, the last stage is the flushing of the reservoir to remove excess proppant from the borehole and to propel the proppant further into the formation. The flushing fluid can be either water or the same material used to start the process.[17]

The pressure in the hole is closely monitored throughout the process so that any significant leakage of the fracing fluid past the packers and away from the productive zone is immediately detected. If a leak is detected, the operation can be stopped. Leaks at or near the bottom of the casing string are separated by hundreds or thousands of feet of intervening strata from shallower freshwater aquifers.[18]

Nearly all oil and gas wells experience a gradual drop off in production over time; this is called a "decline curve" by petroleum engineers.[19] While the new "fraced" wells are initially prolific, their rates of production have been found to drop off quickly in the Barnett Shale and elsewhere. If this trend carries to other shale gas plays, the productive lifespan of shale gas wells will be shorter than traditional gas wells. This means that to maintain high and steady gas production from a portfolio of assets, developers must continuously drill wells to replace wells

15 *Id*.
16 *Id*. at 18.
17 *Id*.
18 *Id*. at 21.
19 *Manual of Oil and Gas Terms, supra* note 8.

that quickly become uneconomic.[20]

Fracing operations are noisy. All natural gas production results in temporary noise from drilling and subsequent fracing that can last from two weeks to over a month. Noise curtailment is usually a function of local law and is measured and controlled in multiple ways. The simplest type of local noise ordinance sets a direct limit on noise caused by drilling and fracing operations. Such regulations typically prohibit noise greater than 70-90 decibels as measured from 200-400 feet from the edge of a site. To cut down on fracing noise, companies have put "sound blankets" resembling large, heavy quilts around the equipment. In other municipalities, an averaging method is used. For example, Fort Worth, Texas requires that drilling and fracing be no more than five decibels higher during the day than the ambient (background) noise and no more than three decibels higher at night. In such cases, wellsites are usually situated as close to a road as possible to minimize access costs and to take advantage of a higher ambient noise level.[21]

The logistical and physical infrastructure demands of fracing operations involve a great deal of personnel and materials and traffic to and from the drillsite. Typically, fracing fluid is mixed offsite in the yard of the contractor conducting the fracing operations. Here, the water is mixed with any additives before being trucked onsite. Fracing operations often require one or two acres in addition to the original drilling pad where the multitude of tanker trucks and other vehicles and equipment can congregate.[22]

Oil companies typically hire specialized contractors to conduct fracing operations. These contractors are protective of the exact recipe of their fracing fluids, considering the ingredients and the ratio with which the ingredients are mixed with the water to make the fracing fluid to be trade secrets. The general constituents of fracing fluids are known, however, and in addition to the 99.5% sand and water, made be 0.5% salt, acid, distillates, ethylene glycol, isopropanol and sodium or potassium carbonate.[23]

With today's technology, a typical fracing operation in the Marcellus Shale requires between one to five million gallons of fracing fluid, mostly water, per well.[24] About twenty to forty percent (20%-40%) of the fluid can be expected to return to the surface through the borehole after the proppant has been injected and the water is being drawn out. In general, there are three ways to deal with fracing fluid left over from operations: (i) inject it back via a disposal

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20 Arthur Berman, *Lessons from the Barnett Shale Suggest Caution in Other Shale Plays*, ASPO-USA, (August 10, 2009) *available at* http://www.aspousa.org/index.php/2009/08/lessons-from-the-barnett-shale-suggest-caution-in-other-shale-plays/ (last visited May 9, 2010).

21 Ft. Worth Municipal Code, Chapter 15, Article II, §§ 15-30 *et seq.* (2006).

22 Michele Rodgers, et al., *Marcellus Shale: What Local Governments Need to Know*, Penn State College of Agricultural Sciences (2008) p. 11, *available at* www.naturalgas.psu.edu (last visited May 9. 2010). The frequency of drilling activity in a locale, rural or urban, and its associated impact on the local populace can present a wide variety of challenges which require the formulation of solutions by the operators, service companies and not uncommonly state and local regulatory Agencies. These challenges and their solutions will be addressed, *infra*.

23 Groundwater Protection Council, *Modern Gas Shale Development in the United States*, April 2009, p. 78, graphic representation *available at* http://www.energyindepth.org/frac-fluid.pdf (last visited May 1, 2010).

24 Michele Rodgers, et al., *supra* note 22, at 4.

well, similar to those used to dispose excess brine from more traditional operations; (ii) treat the fluid through evaporation and/or settling at the surface; or (iii) gather the used fracing fluid, dilute it with freshwater, and truck or pipe it to another project and reuse it again.[25]

The third method is the least expensive and is favored for its seemingly sound environmental underpinnings. However, the used fracing fluid typically must be treated upon its return to the surface. Used fracing fluid must have solids removed for optimum results upon re-injection and to prevent the hydrogen sulfide (H_2S) or iron sulfide (FeS) from returning with the "flowback" on the fracing fluid as it returns to the surface through the borehole. Disposal of the fracing fluid is another option, with costs dependent on the number and proximity of disposal wells near the fracing operations.[26] This method is more difficult in areas such as the Appalachians as less disposal wells are currently available than in regions where prior development has occurred. Solids in the used fracing fluid are again a concern as they could block up disposal wells or contain naturally occurring radioactive materials ("*NORM*"). Treatment at the surface is potentially the most expensive, as pits for settling and transportation of the fluid to a crystallization/evaporation treatment plant—if either is available—is potentially expensive. However, such costly treatment may be necessary if environmental regulations require a complete reduction of additives and no reuse or injection outlets are allowed or available.[27]

Fracing Operations Nationwide

Fracing operations are found wherever the combination of (1) tight shale located reasonably close to the surface, (2) trapped gas or oil within the shale, and, if necessary (3), a market for the produced gas can be found.[28] In the east, the Marcellus dominates production. In the central states, the Barnett is perhaps the best known but is not the only gas shale in Texas, as interest and activity is also found around the Haynesville Shale in East Texas, the Eagle Ford Shale in South Texas, and analogous Barnett Shale prospects in the western panhandle of Texas, among others, have been considered. The Williston Basin in western North Dakota and Eastern Montana is the site of the Bakken formation, a layer of rock which is reputed to hold the largest accumulation of oil identified in North America since 1968, a veritable "sea of oil." estimated by the head of North Dakota's department of mineral resources as potentially containing eleven billion barrels of oil that can be obtained using current technology.[29]

<u>Marcellus and Utica Shale</u>

The Marcellus Shale is truly enormous, a national wonder extending from New York to

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25 Colter Cookson, *Technologies Enable Frac Water Reuse*, AMERICAN OIL & GAS REPORTER, March 2010, at 106.

26 *Id*.

27 *Id*. at 108.

28 The U.S. Energy Information Administration maintains a map of shale gas plays which is periodically updated and *available at* http://www.eia.doe.gov/oil_gas/rpd/shale_gas.pdf (last visited May 10, 2010).

29 Eric Konigsberg, *Kuwait on the Prairie*, The New Yorker (April 25, 2011), *available at* http://www.newyorker.com/reporting/2011/04/25/110425fa_fact_konigsberg#ixzz1KdQI87Co (last visited August 9, 2011).

Tennessee along a swath of territory larger than Greece. Other formations have periodically provided booms of gas production along the Appalachian front, but the Marcellus appears the first to have multi-decade potential with national implications. One example of a prior "false start" was the regional natural gas boom in Clinton County, Pennsylvania, kicked off in early 1950 with the discovery of commercial deposits in the Oriskany Sandstone near Renovo by Dorcie Calhoun.[30] This discovery led to a ten-year rush of gas speculation and development in the area which petered out in the 1960s, leading most wells resulting from the boom to be used for gas storage thereafter.[31] While some potential for natural gas exists in traditional semi-economic fields like the Oriskany Sandstone or the Trenton Limestone—an emerging gas producer in the Central Appalachians[32]—much of the future natural gas potential in the Appalachian Basin lies in Lower Paleozoic shale like the Marcellus and Utica formation.

The Middle Devonian-aged Marcellus, named after the town of the same name in Onondaga County, New York where it outcrops, is a dark-gray to black, fissile, thinly-laminated carbonaceous shale with pyritic inclusions.[33] The Marcellus varies between 40 to 200 feet think and is located in the middle of the Middle/Lower Devonian-aged Hamilton Group.[34] It lies below the Tully Sandstone and above the Lower Devonian Onondaga Limestone, a three-tiered sequence which serves to trap gas within the Marcellus and which provides strong density contrasts at the formation interfaces which in turn provide strong positive reflections on seismic reflection date, greatly assisting interpreters in identifying the formation on seismic.[35] Oil and gas slow the propagation of P-waves (compressional waves—the waves measured and analyzed by geophysicists interpreting seismic data) as they travel through the gas-bearing formation, and thus often result in negative amplitudes at the interface above a hydrocarbon reservoir like the Marcellus. These two factors make the interval containing the Marcellus typically easy to identify on seismic data.

Although thought to contain natural gas potential for some time,[36] drilling in the Marcellus only began in earnest in 2007, when horizontal drilling and hydraulic fracturing became prevalent. By late 2008, 217 wells had been completed in the Marcellus in Pennsylvania and over 520 well permits had been issued by the state.[37] Currently, drilling is concentrated in the Pennsylvania counties of Greene, Fayette, Washington and Westmoreland, the West Virginia counties of Wetzel and Marshall, and along the northern tier of Pennsylvania counties with

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30 Matt Connor, *Well Ahead of His Time*, MOUNTAIN HOME, April 2011, at 9.

31 *Id*. at 12.

32 *See* Christopher Kulander, "Regional Seismic Lines in West Virginia—A Preliminary Look at the Rome Trough and Its Implications for Energy Resources," U.S. Geological Survey Open File Report OFR-01-127.

33 *See* Christopher Kulander and Robert Ryder, "Regional Seismic Lines Across the Rome Trough and Alleghany Plateau of northern West Virginia, western Maryland, and southwestern Pennsylvania," U.S. Geological Survey, Geological Investigations Series Map I-2791, 2005, *available at* http://pubs.usgs.gov/imap/i2791/ (last visited July 23, 2011).

34 *Id*.

35 *Id.* at 4.

36 *Id.* at 8 ("Presently the Marcellus Shale is only marginally productive but it has potential gas in most of the study area.")

37 Harper, J. *The Marcellus Shale—an "Old" New Gas Reservoir in Pennsylvania*, PENNSYLVANIA GEOLOGY, Vol. 28, No. 1, 2008.

Wellsboro in Tioga County becoming a major staging area for operations.[38] Before the permit moratorium that currently has halted drilling in New York, the southern tier of western New York counties were thought to be extremely prospective for Marcellus natural gas. Drilling is also beginning in northeastern Ohio, with activity proliferating in and around Columbiana and Jefferson counties. Estimates of gas in the Marcellus vary. In 2008, a Penn State researcher estimated that the formation contains 363 trillion cubic feet ("*Tcf*") of recoverable natural gas.[39] In April 2009, the U.S. Department of Energy estimated the Marcellus to contain 262 Tcf of recoverable gas.[40] Production depths vary from 4,000 to 8,500 feet and the average well spacing is between 40 and 160 acres per well.[41]

The Middle Ordovician-aged Utica Shale lies lower in the stratigraphic column than the Marcellus over a largely analogous area in the northeast portion of the U.S. and Canada. The Utica Shale occurs in outcrops in upstate New York (where in takes its name from the city of Utica) and extends to the subsurface in the Canadian provinces of Quebec and Ontario. In West Virginia, the Utica Shale is considered the upper part of the Trenton Group; in Ohio, the name 'Trenton Group' is abandoned and replaced by the Trenton Limestone and the overlying Utica Shale.[42] Currently, the Utica is prospective in eastern Ohio and in western Pennsylvania.[43] It varies in depth from 7,000 to 8,000 feet from west to east, dipping eastward toward the Appalachian Basin. It reaches a thickness of up to 1,000 feet (300 m) within the Appalachian Basin and can be as thin as 70 feet (20 m) towards the margins. 250 feet (80 m) are exposed in the section.[44]

<u>Barnett Shale</u>

Most people are familiar with the Mississippian-aged Barnett Shale which is found in and around the Fort Worth region in north central Texas, covering about 5,000 square miles. Prior to economic fracing technology and higher gas prices, the Barnett Shale was considered a "trap rock" that held oil and gas within more traditional reservoirs below it. By 2000, however, higher gas prices and better horizontal drilling technology led to a deluge of gas production in and

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38 Del Torkelson, *Marcellus and Haynesville Grab Industry's Attention as Gas Shale Giants*, AMERICAN OIL & GAS REPORTER, March 2010, at 74.*See also* Jon Hurdle, *Natural Gas Boom Brings Riches to a Rural Town*, Reuters, filed April 5, 2010.

39 Terry Engelder, "*The State of the Marcellus Shale Play in Pennsylvania up through late 2008*", Memorandum to Pennsylvania State Senate Policy Committee, September 30, 2008, *available at* http://www.pasenatepolicy.com/MarcellusShaleHearing/engelder-111808.pdf (last visited July 29, 2011).

40 U.S. Department of Energy (DOE) Office of Fossil Energy. *Modern Shale Gas Development in the United States—A Primer,* p. 17, 2008 (hereinafter "DOE Primer"), *available at* http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf (last visited July 23, 2011).

41 *Id*. at 21.

42 Robert Ryder, "Stratigraphic Framework of Cambrian and Ordovician Rocks in the Central Appalachian Basin", U.S. Geological Survey Bulletin 1839—G, p. 21 (1992).

43 Larry Wickstrom, *et al*. (Ohio Geological Survey), "The Marcellus &Utica Plays in Ohio", Ohio Oil & Gas Association Annual Meeting Proceedings, March 11, 2011, *available at* http://www.ooga.org/docs/2011WinterMeeting/2011WMPresentations/11WM-LWickstromPresentation.pdf (last visited July 23, 2011).

44 *Id.*

around Denton, Tarrant, and Wise counties in Texas, with over 10,000 wells drilled by 2008.[45]

The Barnett itself ranges in depth from 6,500 feet to 8,500 feet and is found below the Marble Falls Limestone and above the Chappel Limestone.[46] Wells in the Barnett are typically horizontal with well spacing ranging from 60 to 160 acres per well, draining a highly variable reservoir thickness of 100 to 600 feet. Government sources place 327 Tcf of gas in the Barnett, with forty-four Tcf being recoverable, and with each ton of shale producing a generous 300-350 scf of natural gas.[47]

Woodford Shale

After success in the Barnett Shale, the hunt was on for analogous shale formations throughout North America. The Late-Devonian/Early-Mississippian-aged Woodford Shale is currently the biggest shale gas target in Oklahoma.[48] In 2004, only twenty-five (25) Woodford Shale gas wells were found in Oklahoma; by 2008, that number had rocketed to 750. Located in south-central portion of the state in and around Coal, Atoka, Pittsburg, and McIntosh counties and extending towards the town of Lawton, the Woodford averages 50-300 feet in thickness. It is located in the Arkoma Basin at an average depth of 6,000 to 12,000 feet, meaning most wells cost three to four million dollars to drill and complete.[49] It shares its top surface with the Osage Lime and overlies undifferentiated strata below.[50]

During the current shale gas rush, natural gas was first produced from the Woodford beginning in 2003 without horizontal drilling. The Woodford play extends over almost 11,000 square miles and currently has a spacing of 640 acres, with future infill drilling possible as the field matures. Relative to other plays, the Woodford has a higher gas content at 200-300 scf and recent estimates place 11.4 Tcf of recoverable gas in the field.[51]

Fayetteville Shale

Located in the Arkoma Basin to the east of the Woodford Shale is Arkansas' biggest shale gas producer, the Mississippian-aged Fayetteville Shale, an organic-rich black shale found at a depth between 550 and 7,000 feet.[52] Producing in north central Arkansas and east central Oklahoma, the Fayetteville is thought to contain over fifty Tcf of gas reserves.[53] It occurs below

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45 DOE Primer, *supra* note 40 at 18.

46 *Id*.

47 *Id*.

48 Brian J. Cardott, Overview of Woodford Gas-Shale Play in Oklahoma, 2008 Update, (talk presented at Oklahoma Gas Shales Conference, October 22, 2008, Oklahoma City, Oklahoma).

49 *Id. Also see* Woodford Shale – Natural Gas Field – Arkoma Basin, *available at* http://oilshalegas.com/woodfordshale.html (last visited May 1, 2010).

50 DOE Primer, *supra* note 40 at 22.

51 *Id*. ("*scf*" = standard cubic feet)

52 Fayetteville Shale, Geology.Com, *available at* http://geology.com/articles/haynesville-shale.shtml, (last visited May 1, 2010).

53 J. Daniel Arthur and Bobbi Jo Coughlin, "Hydraulic Fracturing Consideration for Gas Wells of the Fayetteville Shale, Arkansas Oil & Gas Commission, *available at* http://www.aogc.state.ar.us/ALL%20FayettevilleFrac%20FINAL.pdf (last visited May 1, 2010).

the Pitkin Limestone and above the Batesville Sandstone and has a lateral extent of 9,000 square miles.[54] Development of the Fayetteville began not long after the initial Barnett boom and by 2008 over 600 wells producing 88.85 billion cubic feet ("*Bcf*") per year[55] had been drilled into a highly-variable pay zone averaging in thickness between 20-200 feet.[56] The Fayetteville Shale has a noticeably lower gas content (60 to 220 scf) than the Barnett.[57]

Haynesville Shale

The Upper Jurassic-aged Haynesville Shale is located in northwestern Louisiana and northeastern Texas, with production occurring at depths of 10,000 to 13,500 feet. Production in the Haynesville was jump-started in 2007 and by February of 2010, around eleven percent of the almost 900 rigs drilling for gas onshore in the United States were operating in the Haynesville Shale in Northwest Louisiana, with half of those centered in DeSoto Parish, Louisiana, alone.[58]

The Haynesville Shale is situated between the Cotton Valley Group (above) and the Smackover limestone (below), the latter being a traditional reservoir in its own right all along the northern coast of the Gulf of Mexico.[59] The spatial extent of the Haynesville is approximately 9,000 square miles over which the Haynesville's thickness averages between 200-300 feet.[60] Gas content is more highly variable than most other productive American shale gas formations, with gas content ranging from 100 scf/ton to 350 scf/ton. Recent estimates place 251 Tcf of recoverable gas reserves in the Haynesville.[61]

Eagle Ford Shale

The Cretaceous-aged Eagle Ford Shale has brought riches to portions of Texas that have hitherto not seen the exploration and production that the state is known for. Extending eastward from Maverick and Webb counties along the Rio Grande to a northwest-trending eastern extent running from McMullen to Gonzales counties, Texas, the Eagle Ford produces a significant amount of oil and other liquid hydrocarbons in addition to natural gas, making it an attractive target in the current (and historically unusual) circumstance of high oil and low natural gas prices. The prospective fairway is approximately fifty miles wide and over 400 miles long with an average thickness of 250 feet. The Eagle Ford is found at a depth between 4,000 to 12,000 feet depth and occurs between the Austin Chalk (above) and the Buda Limestone (below).[62] It

54 DOE Primer, *supra* note 40 at 19.
55 Katrina Boughal, *Unconventional Plays Grow in Number After Barnett Shale Blazed the Way*, WORLD OIL MAGAZINE, Vol. 229, no. 8, August, 2008.
56 DOE, *supra* note 40 at 19.
57 *Id*.
58 Torkelson, *supra* note 38 at 74.
59 DOE Primer, *supra* note 40 at 20.
60 *Id*.
61 *Id*.
62 "*Eagle Ford Information*" Texas Railroad Commission field and formation profile, last updated July 12, 2011, *available at* http://www.rrc.state.tx.us/eagleford/index.php (last visited July 29, 2011).

serves as the source rock for the Austin Chalk and the East Texas Field, in addition to itself.[63]

Antrim Shale

The Late Devonian Antrim Shale is potentially prospective over most of the northern half of the lower peninsula of Michigan. The Antrim's perimeter includes within it approximately 12,000 square miles and roughly coincides with the outline of the northern half of the Michigan Basin.[64] Development of traditional reservoirs in the region coincides with the Antrim, such as the Devonian carbonate stacks that enticed producers in the 1980s. The Antrim Shale is analogous stratigraphically to the New Albany Shale (described below).

The Antrim occurs as a brown-black, pyritic, and organic-rich shale, with an average thickness of 60 to 220 feet. In some places, the Antrim includes gray calcareous shale or limestone, along with an intermittent course-grained siltstone at the base. Occurring between the Bedford Shale (above) and the Squaw Bay Limestone (below) at a relatively shallow depth varying from 600-2,200 feet, the Antrim is cheap to drill when compared to other shale plays.[65] Total organic content varies from one to twenty percent (1% to 20%), but the corresponding gas content is low—only averaging between forty and one hundred scf per ton, yielding a modest recoverable reserve estimate of twenty Tcf.[66]

New Albany Shale

Another Midwestern shale, the Late Devonian/Early Mississippian New Albany Shale is located in western Indiana, north-Central Kentucky and eastern Illinois and is part of the Illinois Basin. It is correlative to the Antrim chronologically, and like the Antrim, it is found at relatively shallow depths (500 to 2,000 feet). Spatially, the New Albany coincides with older production that began at the beginning of the twentieth century and has produced four billion barrels of oil to date, according to the U.S. Geological Survey. This aerial extent is large (43,500 square miles) but contains low gas quantities (forty to eighty scf per ton) relative to the Barnett and Marcellus, and a correspondingly low total recoverable reserve estimate of 160 Tcf.[67]

The New Albany is a brownish to grayish-green shale with natural fracture zones that gave rise to natural gas production as far back as the 1800s. It is bounded by limestone above and below, providing a strong seismic reflection signature if the data is corrected for the swallow depth of the formation and its low average thickness, being between twenty and one hundred feet.[68]

Bakken Shale

North Dakota and Montana are also experiencing a surge in development spurred largely

63 *Id*.
64 DOE Primer, *supra* note 40 at 23.
65 *Id*.
66 *Id*.
67 *Id*. at 24.
68 *Id*.

by the Late Devonian to Early Mississippian-aged Bakken Shale in the Williston Basin. Unlike most prospective shale formations to date, the Bakken produces primarily oil, making it an attractive target in 2010 and 2011 as oil rose to over eighty dollars a barrel after the 2007 price drop. Production is largely focused in McKenzie County, North Dakota and Richland County, Montana, and extending as far as southern Saskatchewan and southwestern Manitoba, Canada. In 2008, when only a few wells had been drilled into the Bakken and its viability as a resource was uncertain, USGS estimated the formation to contain 3 to 4.3 billion barrels of undiscovered, technically recoverable oil.[69] Recently, the head of North Dakota's department of mineral resources estimated the Bakken to potentially contain eleven billion barrels of oil that can be obtained using current technology.[70] The Bakken consists of interbedded black shale, siltstone and sandstone deposited in the Williston Basin.[71]

Neighboring Wyoming also has a plethora of smaller productive and potential oil and gas shale, such as the Mowry Shale in the north central portion of the state near Thermopolis and the Green River Shale along the southern border with Colorado and Utah.[72]

Effect on Domestic Production

Fracing operations have helped make possible development of vast natural gas reserves in the United States. Estimates suggest that the U.S. has almost 1,750 Tcf of technically recoverable natural gas, including over 200 Tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place).[73] Technically recoverable unconventional gas—a category which includes gas derived from shale and "tight sandstone" formations as well as coalbed methane ("*CBM*")—accounts for approximately sixty percent (60%) of the onshore recoverable resource.[74] At the U.S. production rates for 2007, about 19.3 Tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next ninety (90) years. Separate estimates of the shale gas resource extend this supply to 116 years.

The use of hydraulic fracturing has been estimated to contribute to thirty percent (30%) of recoverable hydrocarbon reserves in the United States.[75] Fracing is believed to provide an additional 600 Tcf of gas and seven (7) billion barrels of oil that would not be recoverable

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69 "*3 to 4.3 Billion Barrels of Technically Recoverable Oil Assessed in North Dakota and Montana's Bakken Formation—25 Times More Than 1995 Estimate*" U.S. Geological Survey Official Release, April 10, 2008, *available at* http://www.usgs.gov/newsroom/article.asp?ID=1911 (last visited July 28, 2011).

70 Eric Konigsberg, *Kuwait on the Prairie*, The New Yorker (April 25, 2011), *available at* http://www.newyorker.com/reporting/2011/04/25/110425fa_fact_konigsberg#ixzz1KdQI87Co (last visited August 9, 2011).

71 "*The Bakken Formation: News, Map, Videos and Information Sources*," Geology.com, August 2008, *available at* http://geology.com/articles/bakken-formation.shtml (last visited July 28, 2011).

72 *Id*.

73 The Energy Information Administration (Department of Energy) *available at* http://www.eia.doe.gov/.

74 "Modern Shale Gas Development in the United States: a Primer"—U.S. Department of Energy, Office of Fossil Energy *available at* http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf (last visited May 1, 2010).

75 "Hydraulic Fracturing: Effect on Energy Supply, the Economy, and the Environmental"—Independent Petroleum Association of America, April 2008.

without it.[76] Two recent estimates of gas reserves located in the sprawling Marcellus Shale suggest more than 500 Tcf of recoverable reserves.[77]

In June 2004, the U.S. Environmental Protection Agency (the "*EPA*") released the results of a study that found no confirmed instances of contamination of drinking water wells by fracing fluids.[78] This led the federal government to exclude hydraulic fracturing and the associated fracing fluids from coverage under the Safe Drinking Water Act (the "*SDWA*"). Environmentalists and some regulators attacked the findings of the study, saying it was limited to CBM wells. Industry answered by pointing out that the type of well and formation commonly stimulated by fracing does not impact the basic finding of the EPA study—that injection of fracing fluids posed minimal threat to drinking water.

Although hydraulic fracing has been used for decades, the debate over the safety of fracing has become a hot topic because of the current widespread use of the practice and the large number of wells enhanced by fracing. Opponents of fracing, which include environmentalists, politicians and landowners, argue that fracing should be regulated under the SDWA and drilling companies should be required to disclose the chemicals used in fracing fluid.[79] According to The Environmental Working Group, a non-profit environmental organization, drilling companies are avoiding federal law and injecting toxic petroleum distillates into wells and threatening drinking water supplies.[80] Opponents of fracing allege that water supplies are threatened because "30 to 60% of the fracing fluid stays in the geological strata and may escape through the existing or new fractures and contaminate surface groundwater."[81]

What is concerning, opponents claim, is that the additives in fracing fluids are highly poisonous and carcinogenic.[82] The fluids include, they claim, "potentially toxic substances such as diesel fuel, which contain benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals; polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide."[83] The non-profit agency, ProPublica, reported that in July 2008, a hydrologist sampled a water well in rural Sublette County, Wyoming–the home of one of the largest natural gas fields and has thousands of wells that have undergone hydraulic fracing.[84] The test showed that the water "contained benzene…in a concentration

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76 "Hydraulic Fracturing"—American Petroleum Institute. *available at* http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm (last visited May 1, 2010).

77 Torkelson, *supra* note 38 at 74.

78 U.S. Envtl. Prot. Agency, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, 4-15 (2004).

79 *See* The Environmental Working Group, *Drilling Around the Law*, *available at* http://www.ewg.org/files/EWG-2009drillingaroundthelaw.pdf (last visited April 15, 2010).

80 *Id*. at 2.

81 *See* http://www.huntergasactiongroup.com.au/hgfracc.html (last visited April 15, 2010).

82 *See* http://www.earthworksaction.org/FracingDetails.cfm (last visited April 15, 2010).

83 *Id.* citing to EPA's Evaluation of Impacts of Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs Table 4-2 (August 2002).

84 Abrahm Lustgarten, *Buried Secrets: Is Natural Gas Drilling Endangering U.S. Water Supplies?*, ProPublica (November 13, 2008) *available at* http://www.propublica.org/feature/buried-secrets-is-natural-gas-drilling-endangering-us-water-supplies-1113 (last visited April 15, 2010).

1,500 times the level safe for people."[85] According to ProPublica, the Sublette County study is the first to be documented by a federal agency, the U.S. Bureau of Land Management.[86]

People living near areas where hydraulic fracing occurs are also complaining that their water is being contaminated. Landowners are claiming that the water used in fracing operations is being drawn from water sources that have been used for landfills.[87] Furthermore, many landowners claim that the water from their drinking wells changed color and smelled of petroleum after fracing.[88] Many landowners have also claimed that their health has been jeopardized due to the use and consumption of water that has been contaminated by fracing operations.[89] They claim that the chemical additives have caused symptoms ranging from eye and skin irritation to serious respiratory illnesses, such as emphysema, thyroid disorders, tumors, and birth defects.[90]

Industry groups have been quick to rebut allegations that fracing causes water contamination. Energy in Depth, an industry group, argues that fracing opponents need to establish a credible track record of danger.[91] "Unfortunately for them, in hydraulic fracturing they're running up against a technology that in sixty years of service has yet to be credibly tied to the contamination of drinking water."[92] Furthermore, EPA completed a study in 2004 regarding the environmental risks that are associated with hydraulic fracing of coal bed methane wells and found that fracing fluid poses little or no threat to underground sources of drinking water.[93] According to the Ground Water Protection Council, no documented threats exist to underground sources of drinking water by fracing operations.[94] Moreover, industry groups claim that only about one-half of one percent (0.5%) of fracing fluid is made up of chemicals and ninety-nine and a half percent (99.5%) of it is made up of water and proppant.[95] Further, according to the Independent Oil and Gas Association of New York,

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85 *Id*.

86 *Id*.

87 *See* Letter from Peggy Hocutt, resident of Jefferson County, Alabama, to Senator Jesse Bingaman, (D-NM) (date unknown) *available at* http://www.earthworksaction.org/cvPeggyHocutt.cfm (last visited April 15, 2010).

88 *Id*.

89 *Id*.; *see also* Letter from Laura Amos, resident of Garfield County, Colorado, to EarthWorks (date unknown) *available a* http://www.earthworksaction.org/cvLauraAmos.cfm (last visited April 15, 2010).

90 Tom Kenworthy, *Frack Attack: Drilling Technique Under Scrutiny*, American Progress, (June 25, 2009) http://www.americanprogress.org/issues/2009/06/frack_attack.html (last visited April 15, 2010).

91 *See* Energy In Depth, *Frac vs. Fiction* (May 2009), http://s3.amazonaws.com/propublica/assets/natural_gas/frac_fiction_may2009.pdf (last visited April 15, 2010).

92 *Id*. at 1.

93 *See* EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs Study*, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_coalbedmethanestudy.cfm (last visited August 2, 2011).

94 *See State Oil and Natural Gas Regulations Designed to protect Water Resources* (May 2009), http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf (last visited August 2, 2011).

95 Groundwater Protection Council, *supra* note 23.

> "The remaining 0.5 percent of the solution contains three primary additives: a friction reducer, similar to canola oil, which thickens the fluid, and a bactericide, like chlorine, which is used the same way chlorine is used in our drinking water. The fluid also contains a 0.1 percent portion of a micro emulsion element similar to those found in personal care products, such as shampoos, and cutting oils."[96]

In addition to the initial fracing fluid returns back up the wellbore during fracing, studies show that eighty percent (80.0%) or more of the fracing fluid used during the fracing process is eventually recovered from the well out of subsequent production.[97] Additionally, industry groups further claim that fracing does not cause water contamination because the fracing fluids are pushed deep underground, thousands of feet below any aquifers being used for drinking water.[98]

Fracing operations have been alleged to cause or contribute to surface subsidence and even man-made earthquakes. Surface subsidence caused by hydrocarbon and water production is a well-known phenomenon, and because fracing has proved to be such a successful catalyst to production, it may indirectly promote subsidence simply by enhancing the quantity of production. A series of very small temblors with magnitudes of approximately 2.8 on the Richter scale or less were reported on June 2, 2009 in Cleburne, Texas. Some have attributed this seismicity to fracing-stimulated gas production.[99]

According to industry groups, fracing is essential to the viability of oil and gas production in the United States.[100] Hydraulic fracing is estimated by one industry association to be able to provide an additional seven billion barrels of oil and 600 Tcf of natural gas to domestic reserves.[101] Industry groups warn that without fracing, America would be producing much less oil and natural gas, which would in turn increase dependence on foreign imports.[102] Furthermore, hydraulic fracing has brought economic gain for many communities due to production of oil and gas, such as increase of jobs or royalties and taxes paid to the counties and property owners.[103]

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96 *See Get the Facts on Hydraulic Fracturing*, http://www.marcellusfacts.com/pdf/HydraulicFracturingQ&A.pdf (last visited August 2, 2011).

97 Palmer, I.D., *et al.*, *Comparison between gel-fracture and water-fracture simulations in the Black Warrior basin;* Proceedings 1991 Coalbed Methane Symposium, Univ. of Alabama (Tuscaloosa), pp. 233-242.

98 Mike Lee, *Gas-removal method may be subject to more rules*, Fort Worth Star-Telegram (December 7, 2008) (Quoting API officials and industry consultants).

99 Jeff Carlson, "Drilling Might Be Culprit Behind Texas Earthquakes," *Associated Press*. June 12, 2009, *available at* http://www.newsvine.com/_news/2009/06/12/2923921-drilling-might-be-culprit-behind-texas-earthquakes (last visited March 29, 2010).

100 Frac in Depth, Energy in Depth, *available at* http://www.energyindepth.org/in-depth/frac-in-depth (last visited March 29, 2010).

101 Independent Petroleum Association of America – *Hydraulic Fracturing: Effects on Energy Supply, the Economy, and the Environment*, *available at* http://www.energyindepth.com/PDF/Hydraulic-Fracturing-3-E's.pdf (last visited May 3, 2010).

102 *Id*.

103 *Id*.

Oil and Gas Jurisprudence in the Realm of Fracing

Two basic relationships drive the dynamics of oil and gas jurisprudence as it relates to fracing: (i) the vertical relationship between the surface owner and the mineral owner, if the two estates have been separated, and (ii) the lateral relationship between one mineral owner and a neighboring mineral owner.

<u>Surface Ownership vs. Mineral Ownership</u>

If the surface owner is also the mineral owner, then the first question becomes moot. Typically, if the surface owner(s) also owns the mineral estate, he is happy to see the minerals developed as thoroughly as possible, including employment of all secondary and tertiary recovery techniques such as fracing, as this means income in the form of royalty payments. If the mineral estate has been separated from the surface, the surface owner may have no such financial incentive to see minerals developed, and may view the development as a nuisance or harmful to the value of the surface properties.

Historically, the mineral owner dominated the surface owner when the two owners collided over issues relating to land use and mineral development, including fracing. In its most unvarnished form, this dominance meant the mineral owner had "the right to use so much of the surface as may be reasonably necessary to enjoy the mineral estate."[104] Later, the dominance of the mineral owner was attenuated somewhat by the accommodation doctrine in most states, which introduced the circumstance that a disruption of the surface owner's use of the land by subsequent mineral development might require or force the mineral owner to use another "reasonable" method to develop the mineral estate. The accommodation doctrine kept intact, however, the overall doctrine of the dominance of the mineral estate—if no other reasonable method existed for mineral development, then the mineral owner could go ahead with the disruptive development without the surface owner's consent and without being liable for damages for the disruption.

At least ten states have enacted surface damage statutes ("*SDAs*") to help alleviate surface owners/users' displeasure with the perceived imbalance of power that mineral owners have over surface owners/users. They are designed to compensate for damage caused by the mineral owner. Across the states that have passed SDAs, the laws vary surprisingly little with regard to the major components. Most contain entry notification and negotiation requirements to facilitate contact between operators and surface owners and their tenants. Most also contain bonding requirements and protocols on determining surface damage costs. Case law related to such acts is, as yet, sparse. Another common requirement in SDAs is the need for entry negotiations. In these, the surface owner and the producer must begin negotiations before entry to determine what the payment will be for surface damages before the drilling begins—including damages that may be caused by fracing.

Some legal questions are raised by the concept of ownership of the pore space in the rock. If the surface owner owns the pore space, the oil and gas developer should consider

[104] Harris v. Currie, 176 S.W.2d 302, 305 (Tex. 1943).

whether his insertion of fracing fluid and proppants will disrupt the surface owner's use of the pore space for activities such as gas storage or CO2 sequestration, as well as production of materials that have been deemed to belong to the surface owner. This question of pore ownership is still largely the province of case law, with most courts dealing with the issue looking favorably upon the precept that the surface owner owns the pore space.[105] Some states have even memorialized this in their code.[106] The emerging minority view is that the mineral owner owns the pore space.[107] Thus far, no record exists of surface owners attempting to enjoin fracing based on their ownership of the pore space.

Neighboring Mineral Owners

Derived from the common law of England, the rule of capture is used to determine ownership of captured natural resources including groundwater, oil, gas, and—as originally applied—game animals. The rule of capture generally provides that the first person to "capture" a migratory natural resource that is free to roam or flow from property to property and which was never reduced to personal property is granted absolute title to that resource. Trespass, or other related causes of action, only occur when the drill bit "breaks the plane" of the subsurface boundary between two tracts of land.

While the rule of capture may seem like a quaint legal holdover from another era, it still resonates. The advent of prolific fracing has produced for subsurface owners the classic paradox of a benefit and a curse, considering that the inevitable product of fracing has been the legal issues arising from differences between competing subsurface owners over correlative rights. Further complicating matters is that the state law and regulatory framework in the states most affected (*e.g.* Texas, Louisiana, Oklahoma, North Dakota, West Virginia, Pennsylvania, and New York) are themselves non-uniform and, potentially, may face preemption by federal legislation. Consistent with its historical role as a leader in the development of domestic oil and gas resources, Texas, through its Supreme Court, has stepped forward to cast its lot with those favoring few restrictions on the use of hydraulic fracturing to enhance access to and production of hydrocarbons.

The "jury is out" as to whether other states facing these issues will share a similar disposition with specific legislation on the subject of disclosure.

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105 Louisiana: United States v. 43.42 Acres of Land, 520 F.Supp. 1042 (W.D. La. 1981); Mississippi River Transportation Corp. v. Tabor, 757 F.2d 662 (5th Cir. 1985); Michigan: Department of Transportation v. Goike, 560 N.W.2d 354 (Mich. App. 1996); New York: Miles v. Home Gas Co. Cf., 40 A.D.2d 896 (3d Dept. 1972); International Salt Co. v. Geostow, 697 F.Supp. 1258 (W.D.N.Y. 1998), *aff'd by* 878 F.2d 570 (2d. Cir. 1989); Oklahoma: Sunray Oil Co. v. Cortez 112 P.2d 792 (Okla. 1941); Ellis v. Arkansas Louisiana Gas Co. 609 F.2d 436 (10th Cir. 1979); Texas: Getty Oil Co. v. Jones 470 S.W.2d 618 (Tex. 1971); Mapco, Inc. v. Carter, 817 S.W.2d 686, 687 (Tex. 1991) (pore ownership in the case of sandstone or other non-mineral); West Virginia: Tate v. United States Fuel Gas Co.

106 New Mexico: SB 208 (2009); Wyoming: HB 89 (2008).

107 Pennsylvania: United States Steel Corp. v. Hoge, 468 A.2d 1380 (Penn. 1983); Texas*:* Mapco, Inc. v. Carter, 817 S.W.2d 686, 687 (Tex. 1991)(pore ownership in the case of salt or other mineral).

In *Coastal Oil & Gas Corp. v. Garza Energy Trust*,[108] the Texas Supreme Court ironically delivered a fractured decision on the unprecedented question of whether subsurface fracing can give rise to an action for trespass. Earlier decisions by Texas' highest court had addressed the subsurface trespass question, emphasizing in their holdings the importance of the role of the Texas Railroad Commission (the "*RRC*") in regulation. In *Gregg v. Delhi-Taylor Oil Corp.*,[109] the Court held that, in the absence of (1) an explicit legislative grant of exclusive jurisdiction to the RRC and (2) RRC rules or orders governing secondary recovery operations, the courts have jurisdiction to decide the questions of liability and remedies for subsurface trespass, including whether injunctive relief is available to prevent a landowner from fracturing a common formation beyond his property lines for the purpose of increasing the productivity of the landowner's well.[110]

In *Railroad Comm'n of Tex. v. Manziel*, [111] the Texas Supreme Court determined that a mineral estate owner was not entitled to an injunction against an RRC order authorizing a well-spacing exception for conduct of a pressure maintenance project in the East Texas oil field (secondary recovery operations involving the injection of saltwater). [112] In *Manziel*, the Court found that in those circumstances "the subsurface invasion of adjoining mineral estates [sharing a common reservoir] by injected salt water is to be expected, and in the [injunction] case at bar we are not confronted with the tort aspects of such practices." [113] The Court further recognized one commentator's prediction that a "negative rule of capture" may be developing in the face of challenges to secondary recovery operations based on the law of trespass. [114] In examining the evidentiary basis for the RRC order, the Court found persuasive the fact that all other mineral and royalty owners had agreed to the well spacing and that, absent these secondary operations, the complainants' leases "[had], and [would] continue to, produce far in excess of [their] fair share of the oil in place originally recoverable through the use of such methods." [115] As such, the Court chose to defer to the RRC's decisions on such matters, relying heavily on the fact-finding in the RRC decision. [116] In a subsequent decision, the Court flirted with sustaining a subsurface-trespass claim for damages, but ultimately relented by withdrawing its original opinion, leaving intact (without comment or concurrence) the lower court's opinion. [117]

Thus, the stage was set when the Court granted the petition for review of the Corpus Christi Court of Appeal's decision in *Mission Res., Inc. v. Garza Energy Trust*, [118] a case involving a long-running dispute between a producer and the royalty owners of a natural gas lease in South Texas. The Plaintiffs/Respondents ("*Salinas*") were holding a substantial

108 268 S.W.3d 1 (Tex. 2008).
109 344 S.W.2d 411 (Tex. 1961).
110 *Id*. at 414-15.
111 361 S.W.2d 560 (Tex. 1962)
112 *Id*. at 574.
113 *Id*. at 566.
114 *Id*. at 568.
115 *Id*. at 573.
116 *Id*. at 574.
117 Geo-Viking, Inc. v. Tex-Lee Operating Co., 817 S.W.2d 357 (Tex. App.—Texarkana 1991), *writ denied*, 839 S.W.2d 797 (Tex. 1992).
118 166 S.W.3d 301, 310-311 (Tex. App.—Corpus Christi 2005), rev'd, 268 S.W.3d 1 (Tex. 2008).

judgment for money damages against Coastal for subsurface trespass, wrongful drainage, breach of the implied covenant to develop and bad faith pooling. The focus of the original complaint was Coastal's hydraulic fracturing operation of a natural gas well on a lease adjacent to Salinas making it possible for gas to flow from the Salinas lease to the adjacent lease in which Coastal held a larger mineral interest. The Court recognized Salinas's standing to assert an action for trespass, holding that the mineral lessor's reversion interest in the minerals leased to Coastal gave standing to sue for "trespass on the case," a form of trespass that requires proof of actual injury. [119] Noting the limitations of its earlier decisions in *Gregg* and *Manziel*, the Court held that the rule of capture precluded a recovery for Salinas's only claim of injury for trespass, the drainage allegedly caused by Coastal's fracing operation. [120] The Court's limited holding was that "damages for drainage by hydraulic fracturing are precluded by the rule of capture." [121] This ruling, the Court held, made it unnecessary to decide the "broader issue" of whether subsurface fracing can give rise to an action for trespass. [122] The concurring opinion in *Coastal* urged the Court to adopt a bright line rule that "a claim for 'trespass-by-frac' is nonexistent in either drainage or nondrainage cases." [123] By contrast, the dissent complained of the majority's failure to "address Coastal's primary issue: does hydraulic fracturing across lease lines constitute subsurface trespass." [124]

The application of the rule of capture to foreclose Salinas's drainage claims was considered by the Court to be necessary to preserve "unimpeded" the RRC's "power to regulate production to assure a fair recovery by each owner … [which] role should not be supplanted by the law of trespass." [125] However, the Court went on to observe that "[t]hough hydraulic fracturing has been commonplace in the oil and gas industry for over sixty years, neither the Legislature nor the [RRC] has ever seen fit to regulate it…."[126]

Salinas's other damage claims against Coastal (as operator of its lease) for breach of implied covenants (protect against drainage and lease development) and bad-faith pooling fared little better in the final analysis than the trespass claim. Finding no evidence of imprudent operatorship by Coastal and an improper form of jury instruction on the subject, Salinas's claim of a drainage covenant breach by Coastal was denied. [127] While Coastal's challenges to the jury's findings of breach of the development covenant and bad-faith pooling were rejected, the Court nonetheless ordered a new trial due to the trial court's harmful error in the admission of evidence which caused unfair prejudice to Coastal. [128]

119 Coastal, 268 S.W.3d at 9-11.
120 *Id*. at 12-13.
121 *Id*. at 17.
122 *Id*. at 11-12.
123 *Id*. at 30 (Willett, J., concurring).
124 *Id*. at 44 (Johnson, J., Jefferson, C.J., and Medina, J., concurring in part and dissenting in part).
125 *Id*. at 15-16.
126 *Id*. at 17.
127 *Id*. at 19.
128 *Id*.

The Aftermath of Coastal

The Texas Supreme Court in *Coastal* left open multiple options for future claims arising from fracing, as well as contractual options to lessors as protective measures against drainage. The majority opinion reserved judgment on whether trespass could ever qualify as the basis for a claim arising from fracing. While other tort claims are left open as theoretical options, a claimant will face a considerable challenge in meeting the proof requirements for liability and actual damages allegedly caused to a well or formation by fracing. Absent an intentional tort claim (*e.g.* trespass), a recovery of punitive damages is probably foreclosed. If the claimant can show a trespass that threatens imminent harm, other than drainage, injunctive relief remains an option. In the lessor-lessee context, a complaining lessor would have potential claims against the lessee for breach of the implied covenant to develop and bad faith pooling in circumstances similar to *Coastal* where the defendant was also a mineral owner of adjacent acreage.

As additional protective measures, prospective lessors may consider additional lease provisions to guard against a prospective lessee favoring its current or future mineral interests in neighboring lands. These protective measures may appear in the form of affirmative provisions where, *e.g.*, (1) the lessee is required to meet a specific drilling and development schedule and/or (2) the lease imposes on lessee a strict duty to drill an offset well (or take other steps) to protect against drainage where lessee is the operator of or has a working interest in a well on adjoining property. Some leases impose a strict duty to offset without regard to the "reasonably prudent operator" standard in an apparent effort to avoid the burden to a lessor of proving actual drainage and a duty to drill a protection well using the prudent operator standard (*i.e.*, the well will pay out and yield a return on investment).

The *Coastal* opinion may be a departure from the Court's earlier decisions regarding the role of the RRC. The *Gregg* opinion recognized the absence of legislative and RRC activity in the area of secondary recovery operations as a basis for judicial action.[129] The *Manziel* opinion relied on the RRC's exercise of its authority over secondary recovery projects as a basis to avoid judicial action and deny relief for trespass.[130] Neither the Texas legislature nor the RRC has found itself driven to legislate or regulate hydraulic fracturing practices since the Texas Supreme Court denied the Salinas's rehearing motion in November of 2008. The Texas legislature may well share the Supreme Court's view that the RRC is already charged with the dual responsibility to protect correlative rights and to prevent waste in the production of hydrocarbons. In the views of at least one commentator, the RRC would be ill-advised to regulate fracing.[131]

In oil and gas jurisprudence, often times as goes Texas so goes the majority of courts elsewhere. Thus, it may be that it falls to the Texas courts to further establish the framework for resolution of disputes arising from fracing. However, some may argue that *Coastal* highlights the need for legislative or administrative action to clarify the law regarding fracing and to provide a regulatory framework for its use. In his concurring opinion in *Coastal*, Justice Willett maintains

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[129] Gregg, 344 S.W.2d at 418-19.

[130] Manziel, 361 S.W.2d at 568-69.

[131] Owen L. Anderson, *Coastal v. Garza and Its Impact on Subsurface Trespass Issues*, proceedings of the 60th Annual Oil and Gas Law Conference, Inst. for Energy Law, at Tab 8, pp. 20-21, 25-27.

that the Texas legislature has already conferred upon the RRC "sweeping jurisdiction over all Texas oil and gas wells" with the discretion to "weigh the competing interests and strike the proper regulatory balance" with respect to hydraulic fracturing.[132] Having been a chronic subject of controversy and, presuming its importance to Texas (as J. Willett insists), its regulation should not be left to piecemeal judicial resolution but "to the regulators as the Legislature intended."[133]

Portions of the *Coastal* opinion may be subject to change. One of the reasons the Court gives for protecting fracing from trespass actions is that "determining the value of oil and gas drained by hydraulic fracturing is the kind of issue the litigation process is least equipped to handle."[134] The Court, therefore, apparently believed that determination of intrusive fracing or drainage could not be achieved. Since the time of the ruling, however, seismic data gathering and interpretation techniques have advanced such that petroleum seismologists can much better determine the direction and extent of fracturing now than they could even five (5) years ago. These advances mean that, given the proper resources and seismological expertise, a landowner may present evidence that convinces a jury or judge that fracing from a neighboring tract has intruded across the boundary into the plaintiff's tract, and may even provide evidence of the amount of drainage that has occurred or that the fracing on the neighboring tract has caused other harm to his tract or fixtures and improvements thereon.

When looked through the prism of correlative rights instead of only the law of capture, the *Coastal* opinion may also present another challenge by leaving unanswered the effect of fracing on correlative rights and the prevention of waste. State conservation agencies are typically charged with promoting the orderly development of oil and gas while preventing waste and protecting the correlative rights of owners of adjoining tracts.[135] If fracing is found to be beneficial to the development of the entire reservoir, then it is both defensible under the law of capture and the protection of neighbors' correlative rights.

What would be the determination of *Coastal*, however, in the instance that the fracing resulted in harming the ultimate recovery of the entire reservoir, lowering the amount realizable by the neighboring tracts while enhancing only the recovery of the well being fraced? At least one commentator believes that, in such an instance, the correlative rights of the neighboring tracts, where "each owner possesses certain undivided rights within the reservoir," are not addressed by the *Coastal* opinion, and that conservation commissions should consider the ultimate recovery of the reservoir or field.[136] In that light, all the parties sharing the reservoir are co-tenants of a sort, and fracing that boosts one co-tenant's ultimate recovery to the detriment of others sharing reservoir rights may require further scrutiny by the appropriate conservation commission to protect the correlative rights of all the parties sharing the reservoir.

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132 Coastal, 268 S.W.3d at 38.

133 *Id*. at 40

134 *Id*. at 16.

135 *See* Kemp Wilson, *Conservation Acts and Correlative Rights: Has the Pendulum Swung Too Far?* 35 ROCKY MTN. NIN L. INST. (1989); *see also* ROBERT E. SULLIVAN, CONSERVATION OF OIL AND GAS, A LEGAL HISTORY (1960).

136 David E. Pierce, *Minimizing the Environmental Impact of Oil and Gas Development by Maximizing Production Conservation*, 85 N.D. L. Rev. 4 (2010).

Current Fracing Litigation

Recent litigation alleges that fracing poses risks to the health and safety of surface estate owners. One of the chief complaints of landowners nationwide is that fracing contaminates nearby water wells. In *Fiorentin, et al v. Cabot Oil and Gas Corp.*, surface estate owners in Pennsylvania sued Cabot Oil asserting causes of action for negligence, gross negligence, private nuisance, strict liability, breach of contract, fraudulent misrepresentation, and violations of the Pennsylvania Hazardous Sites Cleanup Act.[137] Plaintiff-landowners contend that Cabot's fracing caused several problems, including:

- the release of combustible gas into headspaces of water wells,
- an elevation of methane gas levels in water wells,
- the discharge of natural gas into nearby groundwater,
- excessive pressure within water wells, and
- the release of pollutants, including industrial waste and diesel fuel.[138]

The complaint alleges that an explosion occurred in a water well due to the accumulation of evaporated methane gas caused by fracing.[139] The *Fiorentino* plaintiffs seek damages not only for the diminution of their property values, but also for bodily harm, including neurological, gastrointestinal, and dermatological effects, as well as blood test results consistent with toxic exposure to heavy metals.[140]

Similar cases have been filed by surface estate owners in Texas. In the *Scoma*, *Mitchell*, and *Harris* cases, landowners assert claims for nuisance, trespass, and negligence.[141] These plaintiffs allege that fracing has caused their water wells to become contaminated with heavy metals and chemicals, like aluminum, barium, arsenic,[142] benzene, toluene, etc.[143] Additionally, these plaintiffs allege that the storage and disposal of produced water has caused their own water to turn an orange-yellow color, to taste bad, and to emit foul odors.[144] Plaintiffs contend that they can no longer use their water for consumption, bathing, or laundry due to the contamination.[145] The Texas landowners seek damages for diminution of property values, loss of use and enjoyment of their properties, mental and emotional anguish, and future medical monitoring due to an increased risk of serious latent diseases.[146]

Some communities have even begun preemptively filing lawsuits to protect themselves

137 No. 3:09-cv-02284-JEJ, (M.D. Pa. filed May 17, 2010).

138 *Id.*

139 *Id.*

140 *Id.*

141 *Scoma v. Chesapeake*, No. 3:10-cv-01385-N, (N.D. Tex. filed Aug. 11, 2010); *Mitchell v. Encana Oil & Gas; Chesapeake*, No. 3:10-cv-02555-L (N.D. Tex. filed April 25, 2011); *Harris v. Devon Energy Production*, No. 4:10-cv-00708-ALM, (N.D. Tex. filed April 8, 2011).

142 *Harris, supra* note 141.

143 *Scoma, supra* note 141.

144 *Mitchell* and *Scoma, supra* note 141.

145 *Mitchell* and *Harris, supra* note 141.

146 *See Scoma, Harris,* and *Mitchell, supra* note 141.

from the alleged dangers of fracing. In July 2011, an Aspen law firm filed a class action suit on behalf of the five thousand residents of the Battlement Mesa subdivision when Antero Resources announced plans to drill two hundred new wells in the area.[147] The complaint requests health monitoring for the residents, as well as compensation for diminution of property values and quality of life.[148]

State Regulation of Hydraulic Fracturing

Though specific state rules vary, common state law provisions include fracturing into existing laws and regulations and require that logs and pressure test results are included in disclosures to state authorities. State rules also typically require information on what is in the frac fluid; what are the plans for disposal; the minimum depth for fracturing; and how a fresh water aquifer or surface water asset will be remediated or replaced.

Arkansas

Hydraulic fracturing is currently subject both to formal regulation, as well as the overarching oil, gas, and environmental regulations of the state. The Arkansas Oil and Gas Commission (the "*AOGC*") regulates oil and gas in Arkansas and promulgates and administers regulations to "serve the public regarding oil and gas matters, prevent waste, encourage conservation, and protect the correlative rights of ownership associated with the production of oil, natural gas and brine, while protecting the environment during the production process."[149] Typical protective measures are required, such as requiring owners and operators to case off fresh water from oil- or gas-producing formations that an operator encounters while drilling, and the AOGC requires owners and operators to set and cement surface and down-hole casing to prevent contamination to any freshwater aquifers.[150]

The AOGC recently adopted new regulations that specifically address fracing. Rule B-19 sets design requirements on casing and cementing to protect aquifers.[151] The permit holders must notify the AOGC within twenty-four hours if the setting "does not occur as submitted in accordance with [the] Rule" and would cause a reasonably prudent permit holder "to question the integrity of the cementing program with respect to isolating the zone of Hydraulic Fracturing Treatment from movement of fracture fluids up-hole into the various casing or well bore annuli."[152] Additionally, the permit holder must notify the AOGC of any change in annulus pressure that might indicate a casing failure or that exceeds the rated casing pressure within

147 John Colson, *Class Action Suit Filed Against Antero Resources*, POST INDEPENDENT (July 21, 2011), *available at* http://www.postindependent.com/article/20110721/VALLEYNEWS/110729994/1083&ParentProfile=1074 *see also, Post Independent Opinion: Lawsuit May Be Only Way to Get the Truth about Fracking*, op-ed, POST INDEPENDENT (July 29, 2011), *available at* http://www.postindependent.com/article/20110729/VALLEYNEWS/110729862/1020.

148 *Id.*

149 ARK. CODE ANN. § 15-17-101 (2011); *see also* ARK. OIL AND GAS COMM'N, MISSION STATEMENT (2010), *available at* http://www.aogc.state.ar.us/mission.pdf.

150 ARK. CODE ANN. § 15-72-206; ARK. OIL AND GAS COMM'N, GEN. R. AND REG. B-15 (2011).

151 ARK. OIL AND GAS COMM'N, GEN. R. AND REG. B-19(e) (2011).

152 *Id.* at B-19(f).

twenty-four hours of the event.[153]

Following the completion of a frac job, the permit holder must report maximum pump pressure and the estimated fracture height to be achieved as designed.[154] The permit holder must also identify the types and volumes of the fracing fluid and proppant used for each stage of the fracturing treatment.[155] Rule B-19 also requires the permit holder to produce a list of additives used during the treatment process, categorized by general type and identifying the specific additives for each additive type.[156] If permit holder does not disclose an additive used during the treatment process, he must disclose "a list of all Chemical Constituents and associated CAS [Chemical Abstracts Service] numbers contained in all such Additives[.]"[157] If required to disclose in this manner, the permit holder may petition to have the AOGC hold in confidence any chemical constituent protected by trade secret law.[158]

Finally, operators must disclose and maintain separate master lists of all of the following materials used in fracturing treatments in the state: (1) fracing fluids; (2) additives; and (3) chemical constituents and associated CAS numbers, with the understanding that the operator may petition to have any chemical constituent protected by trade secret law held in confidence by the AOGC.[159] The operator must provide the permit holder with the same information, except that he may withhold any chemical constituent protected by trade secret law.[160]

Two governmental bodies are primarily responsible for overseeing environmental regulation in Arkansas. The Arkansas Pollution Control and Ecology Commission (the "*APCEC*") is responsible for creating and promulgating environmental regulations, but does not have any power of enforcement.[161] The Arkansas Department of Environmental Quality (the "*ADEQ*"), on the other hand, is responsible for administering and overseeing implementation of the policies promulgated by the APCEC.[162] The Arkansas Department of Health exercises limited jurisdiction over groundwater protection as the designated agency in charge of compliance with the federal Wellhead Protection Program.[163]

The ADEQ is specifically charged with enforcing the provisions of the Arkansas Water

153 *Id.* at B-19(h).
154 *Id.* at B-19(k)(1), (3).
155 *Id.* at B-19(k)(2).
156 *Id.* at B-19(k)(4)-(5).
157 *Id.* at B-19(k)(8).
158 *Id.*
159 *Id.* at B-19(l)(3).
160 *Id.* at B-19(l)(4).
161 ARK. CODE ANN. § 8-4-104.
162 *Id.* § 25-14-101.
163 *See* Letter from Bill Clinton, Governor, Ark., to Lee M. Thomas, Admin'r, EPA (July 31, 1986), *reprinted in* Ark. Dep't of Health, *Wellhead Protection Program, in* ARK. DEP'T OF HEALTH, ARKANSAS SOURCE WATER ASSESSMENT PLAN 105, 134 app. A (1999), *available at* http://www.healthy.arkansas.gov/programsServices/environmentalHealth/Engineering/Documents/Reports/FormsAndMaterials/DraftArkansasSourceWaterAssessmentPlan.pdf (designating ADH as the lead agency in implementing 1986 amendments to the federal Safe Drinking Water Act, including the Wellhead Protection Program).

and Air Pollution Control Act (the "*APC Act*") and regulations promulgated pursuant to the APC Act by the APCEC.[164] The Act prohibits a number of pollution-related activities, including generally prohibiting "causing pollution," as that term is defined by the APC Act, in any of Arkansas' waters.[165] Additionally, Regulation 1 of the APCEC specifically applies to all oil and gas wells in the state and prohibits the discharge of salt water or other oilfield waste onto the ground or into state waters.[166] Rule B-19 addresses wastes not already regulated by the ADEQ, regulating storage in sound containment vessels and the reporting of spills.[167]

Fracing operations may also involve specific handling and disposal procedures with respect to flowback water or other fluids used during fracing operations. In 2007, the ADEQ created a procedure by which owners and operators may apply for a general land application permit to dispose of "water based drilling fluids generated or utilized during oil and gas drilling operations."[168] However, the ADEQ specifically excepted "frac water [and] flow-back water" from eligibility for a general land application permit.[169] The ADEQ further noted in the response to comments it had received from industry to the general land application permit that "[p]ermittees are prohibited from storing fluids generated during the fracing process in clay-lined pits …[and that such fluids] must be disposed at an appropriately permitted facility."[170] As a result, it appears that the ADEQ may require that owners and operators arrange for off-site disposal of fracing fluids at proper disposal facilities. As of yet, no Arkansas case specifically addresses fracing. Additionally, there are currently no legislative proposals that specifically address fracing.

Kansas

As of August 25, 2011, no laws or regulations specifically address fracing in Kansas.[171]

Louisiana

Louisiana oil and gas regulations are promulgated and enforced by the Office of

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164 ARK. CODE ANN. §§ 8-1-202, -4-202.

165 *Id.* § 8-4-217. For purposes of the Arkansas Water and Air Pollution Control Act, pollution is broadly defined as "such contamination or other alteration of the physical, chemical, or biological properties of any waters of the state, or such discharge of any liquid, gaseous, or solid substance in any waters of the state as will, or is likely to, render the waters harmful, detrimental, or injurious to public health, safety, or welfare; to domestic, commercial, industrial, agricultural, recreational, or other legitimate beneficial uses; or to livestock, wild animals, birds, fish, or other aquatic life[.]" *Id.* § 8-4-102(6).

166 ARK. POLLUTION CONTROL AND ECOLOGY COMM'N, REGULATION NO. 1 (1993), *available at* http://www.adeq.state.ar.us/regs/files/reg01_final_930316.pdf (last visited on Sep. 25, 2011).

167 *Id.*

168 Ark. Dep't of Envtl. Quality: Pollution Control Div., *Land Application of Water-Based Drilling Fluids*, ARK. DEP'T OF ENVTL QUALITY, http://www.adeq.state.ar.us/water/branch_permits/nodischarge_permits/default.htm (last visited June 30, 2011).

169 *Id.*

170 ARK. DEP'T OF ENVTL QUALITY, RESPONSE TO COMMENTS: PERMIT NUMBER 00000-WG-LA, *available at* http://www.adeq.state.ar.us/water/branch_permits/pdfs/00000-WG-LA_response_to_comments.pdf.

171 David Pierce, Professor of Oil & Gas Law, Washburn University School of Law.

Conservation within the Louisiana's Department of Natural Resources. The Office of Conservation has primary statutory responsibility for regulation and conservation related to development oil, gas, lignite, and other natural resources.[172] Louisiana has limited regulations with regard to fracing, and most of those are applicable to all oil and gas wells and injection well construction and operations.[173] Slurry fracture injection wells, a type of waste disposal well that mixes the waste with water before injection, must comply with the applicable general requirements, public notice requirements, work permit requirements, legal permit conditions, permit transfer requirements, mechanical integrity pressure testing requirements, confinement of fluid requirements, and plugging and abandonment requirements of Louisiana law.[174]

Louisiana has passed detailed regulations dealing with disposal of exploration and production wastes by slurry fracture injection, including use of exploration and production wastes for fracing. The regulations mandate particular application requirements in title 43, part XIX, section 433(C); geological criteria for injection and confining zones in section 433(E); construction requirements in section 433(G); logging and testing requirements in section 433(H); monitoring requirements in section 433(I); operational requirements in section 433(J); reporting requirements in section 433(K); and permitting requirements in section 433(L).[175]

Louisiana has also adopted specific rules related to the reuse of exploration and production waste in fracing operations.[176] Under the current regulations, an operator of record is entitled to a single use of exploration and production waste water to complete fracing operations on one well before being required to dispose of the waste. At the conclusion of fracing operations, all exploration and production waste must be disposed of onsite in accordance with title 43, part XIX, sections 311 and 313 or disposed of offsite in accordance with sections 501 thru 569. Recently, the state has eliminated the one-time usage limitation on exploration and production waste, allowing unlimited recycling.[177] The purpose of the proposed changes is to ease restrictions on reuse of exploration and production effluent and decrease use of the limited freshwater aquifer resources of the Haynesville Shale region.

When fracing operations use groundwater instead of exploration and production waste, current regulations require that the owners of the well that is intended to provide the fracing water provide sixty (60) days notice to the Office of Conservation before using groundwater for fracing operations or any other non-domestic purpose.[178] The Office of Conservation has recently reaffirmed that a well owner's failure to properly notify the state could result in civil penalties.[179] Newly-enacted rules also add a reporting requirement that calls for operators conducting fracing to report the source of water and volume used in the process, including

[172] LA. REV. STAT. ANN. §§ 30:1, 4 (2011).
[173] *See generally* LA. ADMIN. CODE tit. 43, pt. XIX (2011).
[174] *See generally id*. §§ 401-43.
[175] *See id.* § 433.
[176] *Id*. § 313.
[177] 36 LA. REG. 1264, 1264–65 (June 20, 2010).
[178] LA. REV. STAT. ANN. § 38:3097.3 (2011).
[179] *See* Office of Conservation, La. Dep't of Natural Res., *Office of Conservation Reinforces that Domestic Water Well Owners Must Notify Before Selling Water for Industrial Purposes*, DEP'T OF NATURAL RES., http://dnr.louisiana.gov/index.cfm?md=newsroom&tmp=detail&aid=402 (last visited July 5, 2011).

identifying either the water well number or water body name from which the water is drawn.[180]

To further protect groundwater resources, Louisiana regulations limit pump pressure to ensure that vertical fractures will not extend to the base of any underground source of drinking water ("*USDW*") or groundwater aquifer.[181] In addition, permit applications must include information showing that injection into the proposed zone will not initiate fractures through the overlying strata, which could enable the injection fluid or formation fluid to enter an underground source of drinking water.[182]

The Louisiana Commissioner of Conservation recently issued an order establishing "reasonable and uniform practices, safeguards and regulations for present and future operations related to the exploration for and production of gas from the Haynesville Zone in urban areas." The new regulations place specific limits on operating hours, noise pollution, and gas venting related to fracing. Operators covered under the rule must first record "a continuous seventy-two (72) hour ambient noise level at the drillsite." After this is established, no operator may "create any noise which causes the exterior noise level when measured at a distance of five hundred (500) feet from the well head, or other equipment generating noise" that "exceeds the daytime average ambient noise level by more than ten (10) decibels during fracturing or flowback operation."[183] The order also limits fracturing operations to daytime hours, as well as setting limits on the venting and flaring of gas associated with fracturing operations.[184] Municipalities and parishes that had initially resisted a statewide order in favor of more local control have instead adopted rules similar to and consistent with the Commissioner's order.[185]

<u>Maryland</u>

The Maryland Department of the Environment (the "*MDE*") oversees applications and approvals for issuing permits to drill and operate wells for the production of oil and gas in the state of Maryland.[186] However, other than strict permitting requirements,[187] and more general laws and regulations related to exploration and development activities, there are no specific regulations governing fracing. To date, several applications have been filed with the MDE for permits to produce oil and gas in Maryland using hydraulic fracturing, but no such permits have been issued.[188]

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180 *See* Office of Conservation, La. Dep't of Natural Res., *State Office of Conservation Requiring Reporting of Water Source in Hydraulic Fracturing Operations*, DEP'T OF NATURAL RES., http://dnr.louisiana.gov/index.cfm?md=newsroom&tmp=detail&aid=398 (last visited July 5, 2011).

181 LA. ADMIN. CODE tit. 43, pt. XIX, § 315(A).

182 *Id*. § 405(B). This evidence includes a plat showing the disposal well or enhanced recovery project, a copy of the Well History and Work Resume Report, a schematic diagram of the well, and all proposed operating data. *Id.*

183 OFFICE OF CONSERVATION, LA. DEP'T OF NATURAL RES., ORDER NO. U-HS 3(I)(2)(b), *available at* http://dnr.louisiana.gov/assets/docs/news/2009/U-HS.pdf (last visited July 5, 2011).

184 *See id*. at 3(F), (H).

185 *See, e.g.*, SHREVEPORT, LA., CODE OF ORDINANCES ch. 25, arts. I–II (2011).

186 *See* MD. R. 26.19.01.07.

187 *See* MD. R. 26.19.01.06.

188 EXEC. ORDER NO. 01.01.2011.11 (2011).

There have been several significant recent developments related to the regulation of fracing which have been prompted by issues faced by regulators in states where Marcellus Shale drilling has already begun. On March 21, 2011, Maryland's House of Representatives voted 98-40 in favor of HB 852, a de-facto moratorium on facing in the state.[189] The bill is known as the Maryland Shale Safe Drilling Act of 2011 and essentially seeks to restrict shale development until 2013 in order to allow for the completion of a major two-year drinking water and environmental assessment.[190] The bill was first read in the Maryland Senate on March 24, 2011.[191]

On June 6, 2011, Governor Martin O'Malley issued an executive order requiring two Maryland Agencies, the MDE and the Department of Natural Resources (the "*DNR*"), to conduct a study on the impacts of natural gas drilling in the Marcellus Shale.[192] This executive order, known as The Marcellus Shale Safe Drilling Initiative (the "*Safe Drilling Initiative*"), establishes an advisory commission to study the short-term, long-term, and cumulative effects of natural gas exploration and production, best practices and appropriate changes, if any, to the current laws governing oil and gas exploration in Maryland.[193]

In a press release issued by the State of Maryland, the study outlined in the Safe Drilling Initiative is described as follows:

> "The Department of the Environment and Natural Resources, in consultation with the Advisory Commission, will conduct a three-part study and present findings and recommendations as follows:
>
> - By December 31, 2011, a presentation of findings and related recommendations regarding the desirability of legislation to establish revenue sources, such as a State-level severance tax, and the desirability of legislation to establish standards of liability for damages caused by gas exploration and production.
> - By August 1, 2012, recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland.
> - No later than August 1, 2014, a final report with findings and recommendations relating to the impact of Marcellus Shale drilling including possible contamination of groundwater, handling and disposal of wastewater, environmental and natural resources impacts, impacts to forests and important habitats, greenhouse gas emissions, and economic

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189 H.R. 852, REG. SESS. (Md. 2011).

190 *Id*.

191 Maryland General Assembly Homepage, http://mlis.state.md.us/2011rs/billfile/hb0852.htm (last visited on July 31, 2011).

192 EXEC. ORDER NO. 01.01.2011.11 (2011).

193 *Id*.

impact.

- The Executive Order also instructs the Departments and the Advisory Commission to take advantage of other ongoing research. If information becomes available during the course of the study that is sufficient to demonstrate that the natural gas can be extracted from shale formations in Maryland without adverse impact to human health, natural resources, or the environment, the Department could issue permits with all appropriate safeguards in place."[194]

In addition to the restrictions placed on fracing through the Safe Drilling Initiative and the MDE permitting requirements, county and municipal regulations may also apply. For example, the town of Mountain Lake Park in Garrett County, a center of possible shale production in Maryland, has enacted a ban against drilling new gas wells within its jurisdiction.[195]

Michigan

Michigan oil and gas regulations are promulgated and enforced by the Michigan Office of the Geological Survey (the "*OGS*") of the Michigan Department of Natural Resources & Environment (the "*DNRE*"), pursuant to authority granted by the Natural Resources and Michigan's Environmental Protection Act.[196] The OGS reviews applications and issues permits to drill and operate wells for the production of oil and gas. However, other than the Supervisor of Well's[197] Letter of Intent, and more general laws and regulations related to exploration and development activities, hydraulic fracturing is unregulated as it relates to oil and gas production. The Letter of Intent is not a law or regulation, but rather an administrative directive limiting fracturing to a minimum depth of fifty (50) feet below the surface.[198] The Supervisor of Wells has the authority to "regulate the secondary recovery methods of oil and gas, including pulling or creating a vacuum and the introduction of gas, air, water, and other substances into the producing formations."[199] Secondary recovery methods, such as fracing, are regulated by the same rules and regulations that generally regulate oil and gas drilling. No action is required before commencing fracing operations separate from the permits generally required before drilling an oil or gas well.

The permitting process to drill a well requires standard information such as well location, survey of the area, and a written application.[200] For injection wells, the application must include

[194] Press Release, Maryland Department of the Environment, Governor O'Malley Names Members of the Marcellus, Shale Safe Drilling Initiative Advisory Commission, http://www.mde.state.md.us/programs/PressRoom/Pages/071911.aspx.
[195] MOUNTAIN LAKE PARK, MD., ORDINANCE 2011-01 (March 3, 2011).
[196] MICH. COMP. LAWS § 324.501 (2011).
[197] As used in Michigan oil and gas regulations, the Supervisor of Wells is the DNRE or OGS. *See id.* § 324.61501(o).
[198] Personal communication with Mike Bricker, Environmental Manager, Michigan Office of Geological Survey, April 5, 2010.
[199] MICH. COMP. LAWS § 324.61506.
[200] MICH. ADMIN. CODE r. 324.201 (2011).

a statement that the injection of fluids will not exceed the fracture pressure gradient for the subsurface strata, which would appear to prevent fracing unless a well that is using fracing to increase production is not considered an injection well.[201] After completion, the Supervisor of Wells may request copies of service records showing all instances of fracturing[202] and within sixty (60) days of completion, the driller must file a list of all instances of perforating, acidizing, fracturing, shooting and testing.[203] A driller using secondary recovery methods must monitor and record the injection pressure, injection rate and cumulative volume of the fluid injected for each injection well monthly, and report that data to the Supervisor of Wells annually.[204]

Despite the language preventing fracturing in injection wells, Harold Fitch, Director of OGS reported in June 2009 that, "[h]ydraulic fracturing has been utilized extensively for many years in Michigan, in both deep formations and in the relatively shallow Antrim Shale formation. About 9,900 Antrim wells in Michigan produce natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well."[205]

The frequency of hydraulic fracturing, relatively shallow average depth of the Antrim Shale formation and the chemicals used in fracing have raised water pollution concerns.[206] However, Director Fitch has not seen any reason for concern, stating, "[t]here is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way."[207]

The Department of Environmental Quality recently promulgated a new Supervisor of Wells instruction on "high volume hydraulic fracturing." Defined as a "well completion operation that is intended to use a total of more than 100,000 gallons of hydraulic fracturing fluid,"[208] Michigan implemented these new regulations out of concern "unique conditions" that may arise when and if operators begin drilling in the Utica Shale formation.[209] The instruction

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[201] *Id.*

[202] *Id.* at 324.416.

[203] *Id.* at 324.418.

[204] *Id.* at 324.806.

[205] INTERSTATE OIL AND GAS COMPACT COMM'N, *Regulatory Statements On Hydraulic Fracturing Submitted By The States*, *in* TESTIMONY SUBMITTED TO THE HOUSE COMMITTEE ON NATURAL RESOURCES SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES 1-C (2009), *available at* http://www.iogcc.state.ok.us/Websites/iogcc/Images/Additional-IOGCC-Testimony-June2009.pdf.

[206] Brian Creek, *WTF?* [*What the Frack?*] *Hydraulic Fracturing in Antrim Shale Will Impact Water Resources*, THE ROUND RIVER (Mar. 19, 2010), http://theroundriver.com/2010/03/19/wtf-hydraulic-fracturing-in-antrim-shale-will-impact-water-resources/ (last visited July 6, 2011).

[207] IOGCC website, *supra* note 205.

[208] MICH. DEP'T OF ENVTL. QUALITY, SUPERVISOR OF WELLS INSTRUCTION 1-2011, HIGH VOLUME HYDRAULIC FRACTURING WELL COMPLETIONS (2001), *available at* http://www.michigan.gov/documents/deq/SI_1-2011_353936_7.pdf.

[209] *Id.*; Keith B. Hall, *Michigan Issues New Hydraulic Fracturing Regulations*, OIL & GAS LAW BRIEF (June 13, 2011), http://www.oilgaslawbrief.com/hydraulic-fracturing/michigan-issues-new-hydraulic-fracturing-regulations/ (last visited July 7, 2011).

took effect on June 22, 2011.[210]

Before withdrawing water for oil and gas operations, operators of high volume fracturing wells must submit a list of information to the OGS, including: (1) an electronically produced evaluation form; (2) the proposed number, depth, volume, and pumping rate of water withdraw wells; and (3) a supplemental plat of the well site showing the proposed location of all water withdraw wells, all recorded and reasonably identifiable fresh water wells within 1,320 feet of the water withdraw wells, and the location and dimensions of any proposed freshwater pits.[211] Operators must monitor the nearest freshwater well within 1,320 feet of a water withdraw well, collecting data daily and reporting weekly to the OGS district supervisor.[212]

Additionally, freshwater pits must be maintained so as not to create a hazard, may not remain on site after well completion operations, and may be subject to regulations on soil erosion.[213] Operators must also monitor and record surface injection pressure and annulus pressure between the injection string and the next string of casing.[214] Finally, operators must provide the following information along with the record of well completion operations: (1) Material Safety Data Sheets on all chemical additives used (including the volume of each) during the operation; (2) service company fracturing records showing fracturing volumes, rates, and pressures; (3) annulus pressures recorded during the fracing; and (4) the total volume of flowback water (both formation and treatment water) recorded to date at the time of record submittal.[215]

Hydraulic fracturing is also subject to the laws and regulations generally relating to oil and gas drilling operations. Michigan has laws protecting the surface waterways[216] from oil and gas wells[217] and, through them, any damage caused by fracing. These regulations do not specifically address fracing, but generally prohibit any oil and gas activity from causing water contamination. Administrative rules relating to groundwater state that hydraulic fracturing of bedrock for water wells is not permitted without the prior written approval of the health officer.[218]

Local rules are being promulgated. For example, Marquette County Health Department created a Hydraulic Fracturing Request Review Policy that has been adopted by the State of

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210 MICH. DEP'T OF ENVTL. QUALITY, *supra* note 208.

211 *Id.*

212 *Id.*

213 *Id.*

214 *Id.*

215 *Id.*

216 MICH. COMP. LAWS § 324.32301 (defining "connecting waterway" as the St. Mary's River, Detroit River, St. Clair River, or Lake St. Clair).

217 *Id.* § 324.61505a (preventing drilling under the Great Lakes or the connecting waterways); *id.* § 324.61506 (granting the Supervisor of Wells the power to prevent the pollution of water by oil and gas and vice versa).

218 MICH. ADMIN. CODE r. 325.1637.

Michigan.[219] To date, no case law related to fracing exists in Michigan.

Montana

The Montana Board of Oil and Gas Conservation (the "*MBOGC*"), "a quasi-judicial body that is attached to the state's Department of Natural Resources and Conservation for administrative purposes only,"[220] has primary authority—also called "primacy"—over regulating and administering the Montana Underground Injection Control (UIC) Program for Class II injection wells[221] as well as hydraulic fracturing operations. The MBOGC seeks to prevent harm to surrounding land or underground resources caused by oil and gas operations, "including but not limited to regulating the disposal or injection of water and disposal of oil field wastes."[222] It accomplishes this by, among other things, issuing drilling permits, classifying wells, and adopting and enforcing rules.[223]

Effective August 27, 2011, the MBOGC's new regulations governing fracing took effect. Generally, the new rules require disclosure of the chemical composition of fracing fluid within forty-eight hours of fracing operations and further information after completion of operations.[224] Necessary pre-fracing information includes total volume of the injected fluid along with the name and volume of each component, and specifics related to well construction and integrity. In addition, the estimated weight of inert substances, such as proppants, contained in the fracing fluid, and either the maximum estimated pressure during fracturing or certain information regarding the design of the well, must be disclosed.

The requirement to disclose this information in the drilling permit application does not apply for wildcat or exploratory wells or if an operator is unable to know in advance that it will need to conduct hydraulic fracturing as part of well completion, but for those wells the operator must provide the same information in a notice of intent to fracture that is provided to MBOGC at least forty-eight hours in advance of the fracturing operation.[225]

After fracing operations are complete, the operator must then provide the MBOGC with a description of the intervals fraced, the maximum pressure reached during fracing operations, the

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219 MICH. DEP'T OF ENVTL. QUALITY, DRINKING WATER & RADIOLOGICAL PROT. DIV., POLICY/PROCEDURE 1996-5, HYDRAULIC FRACTURING OF WATER WELLS (1996), *available at* www.michigan.gov/documents/deq/deq-wd-gws-wcu-hydraulicfracturing_270750_7.pdf.

220 DNRC Montana Board of Oil & Gas Conservation, *Montana Board of Oil & Gas Conservation*, MT.Gov, http://bogc.dnrc.mt.gov/BoardSummaries.asp (last visited July 7, 2011); *see also* MONT. CODE ANN. § 2-15-3303 (2009) (establishing the MBOGC).

221 DNRC Montana Board of Oil & Gas Conservation, *supra* note 220.

222 MONT. CODE ANN. § 82-11-111(2)(a); *see also* DNRC Montana Board of Oil & Gas Conservation, *supra* note 220.

223 MONT. CODE ANN. §§ 82-11-111(2)(b)-(c), (5)(a).

224 MONT. ADMIN. R. (2011): Rule I (36.22.608), Rule II (36.22.1015), Rule III (36.22.1016), Rule IV (36.22.1106). (MBOGC's new regulations are available at http://bogc.dnrc.mt.gov/PDF/FinalFracRules.pdf (last visited Sep. 23, 2011)).

225 MONT. ADMIN. R. 36.22.308(2) (2011).

chemical names and CAS numbers of each of the additives actually used and their concentration.[226] In the alternative, operators may submit this information to the Interstate Oil and Gas Compact Commission/Groundwater Protection Council, or any other internet repository that can be accessed by the public.[227]

If any required information is entitled to protection as trade secret, the operator may identify the produce by its trade name, inventory name, or any other unique name.[228] However, the operator must disclose the chemical constituents of any protected product if such information is necessary to respond to a spill or medical emergency.[229]

The Montana legislature has authorized the MBOGC to prosecute violations or even threatened violations of MBOGC rules or orders by bringing suit, assessing civil or administrative penalties, or any combination of these remedies.[230] Civil fines range from $75.00 to $10,000.00 per day for each violation, while administrative fines could be as high as $125,000.00 total.[231] Moreover, a willful violation is deemed a misdemeanor and subjects the offender to criminal penalties of up to $10,000.00 per day of violation, imprisonment of up to six (6) months, or both.[232] Finally, violations which are causing or will cause substantial pollution such as would "represent an immediate threat to public health, safety, or welfare" are considered emergencies and authorize the MBOGC to order the immediate cessation or mitigation of the offending behavior, including the immediate closure or shutdown of the injection well.[233]

As for Montana's UIC Program for Class II wells, the purpose of this is to protect aquifers classified as USDWs.[234] The Montana UIC Program for all wells in Montana had previously been implemented directly by the EPA until, after several years of seeking delegation, Montana won state primacy over Class II wells in 1996.[235] All lands within Montana, excluding communal or allotted Indian lands under federal or tribal jurisdiction, are regulated by the Montana UIC Program.[236]

Montana allows operators of Class II injection wells three (3) basic options to dispose of the waste fluid generated through the hydraulic fracturing process. Operators can either (i) "discharge [the fracing fluid] into existing drainages;" (ii) "put it in holding ponds and let it evaporate or seep into the ground;" or (iii) "reinject it into the aquifer" from which it was originally pumped.[237] Although reinjection is currently being given more consideration as the

226 MONT. ADMIN. R. 36.22.1015(1-3) (2011).
227 MONT. ADMIN. R. 36.22.1015(4)(a-b) (2011).
228 *See* generally MONT. ADMIN. R. 36.22.1016 (2011).
229 MONT. ADMIN. R. 36.22.1016(4) (2011).
230 MONT. CODE ANN. § 82-11-147.
231 *Id*. §§ 82-11-149, -147(1)(b).
232 *Id*. § 82-11-148.
233 *Id*. § 82-11-151(1).
234 DNRC Montana Board of Oil & Gas Conservation, *supra* note 220.
235 *Id*.
236 *Id*.
237 *Coal Bed Methane in the News*, MONT. ENVTL. INFO. CTR., http://meic.org/water-quality/coal-bed-methane (last visited July 7, 2011); *see also* MONT. ADMIN. R. 36.22.1226 (noting that produced water containing

only environmentally safe disposal method of the three, it is also an expensive option and one that has not yet been used on a state-wide scale.[238]

While various state industry lobbyists, environmental groups, and members of the MBOGC itself are currently outspoken in debating the relative safety or dangers of utilizing fracing in Class II injection wells, there appears to be no case law discussing Montana's current Class II UIC Program. However, the MBOGC recently proposed new regulations that would require fracing operators to, among other things, disclose the chemical composition of their hydraulic fracturing fluids. The board released the new regulation in May and held public hearings in June of 2011.[239] Under the proposed regulations, operators of both new and existing wells must: (1) describe the intervals or formation treated; (2) disclose the type of treatment pumped into the well; and (3) list the amount and types of material pumped, as well as the rates and maximum pressure during treatment.[240]

In addition, the proposed rules require contain new testing requirements and regulations on reworking or recompletion of wells. Operators must test production or intermediate casing prior to initiating fracture stimulation.[241] The unsupported portion of the casing must be tested to maximum anticipated treating pressure.[242] A test is considered successful under these regulations if pressure is applied for 15 minutes with no more than a five percent loss in pressure.[243] If the casing fails this test, the operator must repair the casing or use a temporary casing string.[244] Additionally, operators must seek board approval before reperforating, recompleting, or reworking a well.[245] However, repairs that "do not substantially change the mechanical configuration of the well bore or casing" and "treatments intended to clean perforations, remove scale or paraffin, or remedy near-well bore damage" do not require prior approval.[246]

<u>New Mexico</u>

New Mexico oil and gas regulations are promulgated and enforced by the Oil Conservation Division ("*OCD*") of New Mexico's Energy, Minerals and Natural Resources Department,[247] pursuant to authority granted by the New Mexico Oil and Gas Act.[248] However, other than notice requirements, and more general laws and regulations related to exploration and development activities, hydraulic fracturing is virtually unregulated. No action is currently

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15,000 parts per million or less of dissolved solids "may be retained and disposed of in any manner allowed by law that does not degrade surface waters or groundwater or cause harm to soils").]

238 *Id.*

239 Notice of Public Hearing on Proposed Adoption - Oil and Gas Well Stimulation, 10 Mont. Admin. Reg. 819, 819 (May 26, 2011).

240 *Id.* at 820.

241 *Id.*

242 *Id.*

243 *Id.* at 822.

244 *Id.* at 821.

245 *Id.* at 822.

246 *Id.*

247 *See* Oil Conservation Division, *available at* http://www.emnrd.state.nm.us/OCD/index.htm (last visited July 7, 2011).

248 N.M. STAT. § 70-2-6 (2011).

required before commencing fracing operations. After completion, notice must be given to the OCD within thirty (30) days, using a form issued by the OCD.[249] The report must include "a detailed account of the work done and the manner in which the operator performed the work; the daily production of oil, gas and water both prior to and after the remedial operation; the size and depth of shots; the quantity and type of crude, chemical or other materials the operator employed in the operation; and any other pertinent information."[250] More elaborate notice is required in cases where operations may significantly impact the target or adjacent formations. If the operations actually injure the target or adjacent formations, or could create underground waste or contaminate any fresh water, notice must be given within five (5) working days of the operator's discovery of the situation, and the operator must then "proceed with diligence to use the appropriate method and means for rectifying the damage."[251] The OCD may require the well to be plugged if the injury is irreparable.[252] No documented cases of aquifer contamination caused by fracing have occurred in New Mexico.[253]

Changes may be coming. On August 8, 2011, the New Mexico Oil and Gas Association ("NMOGA"), the preeminent oil and gas industry group in the state, introduced to OCD a proposal that would require drilling companies to disclose the ingredients of fracing fluids through an online registry.[254] Some companies are already doing this on a voluntary basis. Disclosure under the proposed rule would be required within forty-five days after either completion of the fracing job or completion of the well. An exception for the requirement of disclosure would be information protected as a trade secret. This proposed rule is similar to that adopted in Texas (described below).

Fracing can also raise water pollution concerns. While New Mexico has a Water Quality Act, it is pre-empted and does not apply in its own right to activities already subject to regulation by the OCD pursuant to its power to prevent water pollution. Water Quality Act regulations that could affect oil and gas activities each include a section that states it does not apply to activities regulated by the OCD under the Oil and Gas Act. [255]

In setting forth water quality standards, however, the OCD's oil and gas regulations refer back to the Water Quality Act regulations for guidance. For example, pollution must be controlled so that toxic pollutants, as defined by the Water Quality Act regulations, are not introduced into the water supply, and the concentration of other contaminants must meet the standards set forth in certain Water Quality Act regulations.[256] The Oil and Gas Act provides for authorization of different concentration standards in some situations, such as when abatement of

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249 N.M. CODE R. § 19.15.7.14(G) (2011). Notice is given using form C-103, attached. While some remedial work must be reported before commencing operations, fracing is not included. *Id*. § 19.15.7.14(A).

250 *Id*. § 19.15.7.14(G).

251 *Id.* § 19.15.16.16.

252 *Id*.

253 Mary Lynn Bogle, *Hydraulic Fracturing Regulations in the Rocky Mountain States*, 2nd Conference of the Law of Shale Plays, INST. FOR ENERGY LAW, Sep. 7-8, 2011.

254 *Id*.

255 N.M. STAT. § 74-6-12. *See, e.g.,* N.M. CODE. R. §§ 20.6.2.1201, .3105, .5003.

256 N.M. CODE R. § 19.15.30.9(B)-(C). The applicable Water Quality regulations are §§ 20.6.2.7, 20.6.2.3103, and 20.6.4.

the pollution to required levels is technically infeasible.[257] If pollution exceeds the applicable levels, it must be abated pursuant to an Abatement Plan approved by the Director of the OCD.[258] These regulations do not specifically address fracing, but generally prohibit any oil and gas activity from causing water contamination.

County and municipal regulations may also apply. For example, Santa Fe County enacted an oil and gas ordinance in December 2008 that, among other things, regulates fracing in the county that is not within an incorporated municipality.[259] Fracing activities are generally limited to the hours between 8:00 a.m. and 5:00 p.m., and may not exceed eighty (80) decibels at 300 feet from the source.[260] The contents of the fracing solution are also restricted. Fresh water meeting drinking standards is the only fluid that may be used. The solution may not contain hydrocarbons or other toxic contaminants, synthetic fracturing fluid, or brine. Other fluids may be authorized only if there is "clear and convincing evidence" that fresh water would damage the rock formation such that the oil and gas could not be recovered. [261]

As an example of municipal regulation, the city of Lovington in Lea County, a long-time center of oil and gas production in New Mexico, has also enacted an ordinance that affects fracing. The operator of a secondary recovery injection well must record monthly the injection pressure, injection rate, and cumulative volume of the fluid injected. The previous year's records must be submitted by March 1 of each year to the City Engineer, or operations must cease.[262] Any pressure test failure, significant pressure changes, or evidence of a leak must be verbally reported to the City Engineer within twenty-four (24) hours, and injection must cease if there is evidence that the fluid is not being injected into the correct strata.[263]

New York

Horizontal drilling and hydraulic fracturing techniques have been in common use for several decades in New York.[264] While general drilling regulations exist that affect fracing, anticipation of the development of the Marcellus Shale through high-volume hydraulic fracturing has lead to the proposal of several new laws and regulations.[265]

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257 *Id*. § 19.15.30.9(E)-(F).

258 *Id*. § 19.15.30.11.

259 Santa Fe County, N.M., Santa Fe County Oil and Gas Amendment to the Santa Fe County Land Development Code, Ordinance No. 2008-19 (Dec. 9, 2008) (to be codified in the SANTA FE COUNTY LAND DEVELOPMENT CODE).

260 *Id.* § 11.25.2, .3.

261 *Id*. § 11.25.4.

262 LOVINGTON, N.M., LOVINGTON MUNICIPAL CODE § 8.30.440(C).

263 *Id*. § 8.30.440(F).

264 N.Y. STATE DEP'T OF ENVTL. CONSERVATION, GAS WELL DRILLING IN THE MARCELLUS SHALE (2010), *available at* http://www.dec.ny.gov/energy/46288.html (last visited April 15, 2010).

265 For example, in the 2011 legislative session, at least 17 bills were proposed that would have impacted fracing, but none were enacted. *See*, S. 5592, 233rd Sess. (N.Y. 2011), A. 7400, 233rd Sess. (N.Y. 2011) (would suspend fracing until June 1, 2012, to allow more time to study the effects); S. 2697, 233rd Sess. (N.Y. 2011) (would enact various changes and requirements, including requiring health impact assessments and air quality monitoring); S. 4220, 233rd Sess. (N.Y. 2011), A. 7218, 233rd Sess. (N.Y. 2011) (would

Article 23 of the New York Environmental Conservation Law regulates the development, operation and utilization of oil and gas resources within the state and grants the Department of Environmental Conservation (the "*NYDEC*") the authority to administer such regulation.[266] The regulations enacted by the NYDEC are found in Title 6 of the New York Codes, Rules and Regulations and supersede all local laws relating to oil and gas regulation (except for local government jurisdiction over local roads and real property taxes),[267] however, all drilling and mining operations are still subject to all other laws that may be applicable (*e.g.* water use regulations, regulations on the transportation and storage of chemicals, etc.).

Any drilling project in New York State must pass an environmental review process, and drilling for oil or gas is prohibited without a permit issued by the NYDEC.[268] The NYDEC's discretionary approval of such a permit also triggers the application of the State Environmental Quality Review (the "*SEQR*").[269] A proposal to drill for oil or gas must either complete the full SEQR process,[270] or conform to the conditions and thresholds established in a generic environmental impact statement.[271] In 1992, the NYDEC adopted the Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (the "*1992 GEIS*") to

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prohibit fracing); S. 425, 233rd Sess. (N.Y. 2011), A. 2922, 233rd Sess. (N.Y. 2011) (would, *inter alia*, require disclosure of fracing fluids and ban use of fracing fluids that contain substances that pose a risk to human health); S. 4251, 233rd Sess. (N.Y. 2011), A. 7283, 233rd Sess. (N.Y. 2011) (would require tests and treatment of waste from fracing operations); A. 2924, 233rd Sess. (N.Y. 2011) (would require environmental impact statement for fracing operation); A. 300, 233rd Sess. (N.Y. 2011) (would create moratorium on disposal or processing of fracing fluids originating from outside of New York pending a report by the EPA and review thereof); A. 5677, 233rd Sess. (N.Y. 2011) (would ban fracing on or within one mile of state parks, recreation and historic lands); A. 5547, 233rd Sess. (N.Y. 2011) (would create moratorium on new fracing permits pending a report by the EPA and review thereof); A. 6488, 233rd Sess. (N.Y. 2011) (would require treatment facilities to refuse fracing fluids that contain high levels of radium); A. 6540, 233rd Sess. (N.Y. 2011) (would require certificates of competence for persons, derricks and equipment engaging in fracing); A. 6541, 233rd Sess. (N.Y. 2011) (would place five-year moratorium on high-volume fracing to give time for further research); A. 7072, 233rd Sess. (N.Y. 2011) (would require screening of fracing wastewater to determine if treatment facilities are appropriate and, when not, prohibit the facilities from accepting such wastewater); A. 7172, 233rd Sess. (N.Y. 2011) (would create commission to study economic costs and benefits of fracing in New York State); S. 3765, 233rd Sess. (N.Y. 2011) (would prohibit contracts related to fracing that prohibit the disclosure of chemicals used in fracing); A. 1265, 233rd Sess. (N.Y. 2011) (would allow only natural and organic materials to be used in fracing fluid, and ban the use of toxic materials); A. 6426, 233rd Sess. (N.Y. 2011) (would enact various changes and controls, including disclosure of fracing materials and requiring inspection and audits).

266 N.Y. ENVTL. CONSERV. LAW §§ 23-0301, 23-0303(1) (2010).

267 *Id.* § 23-0303(2).

268 N.Y. COMP. CODES R. & REGS. tit. 6, 552.1(a) (2011).

269 No agency may approve an action that may affect the environment by changing the condition of a natural resource until it has complied with the provisions of SEQR. N.Y. COMP. CODES R. & REGS. tit. 6, 617.3 (2011).

270 *See* N.Y. COMP. CODES R. & REGS. tit. 6, 617.3 (2011); *see also* N.Y. STATE DEP'T OF ENVTL. CONSERVATION, SEQR: GUIDING THE PROCESS (2009), *available at* http://www.dec.ny.gov/docs/permits_ej_operations_pdf/guidfnledits27409.pdf (last visited July 7, 2011).

271 When a generic environmental impact statement has been filed, no further SEQR compliance is required if a subsequent proposed action will be carried out in conformance with the conditions and thresholds established for such actions in the generic environmental impact statement or its findings statement. N.Y. COMP. CODES R. & REGS. tit. 6, 617.10(d)(1) (2011).

establish the basis for environmental review and approval of oil and gas mining projects.[272]

The 1992 GEIS expressly identified and discussed hydraulic fracturing[273] and did not recommend any additional regulatory controls for it.[274] Then, in 2008, the NYDEC determined that some aspects of horizontal drilling and high-volume hydraulic fracturing warranted the further review in the form of a Supplemental Generic Environmental Impact Statement,[275] a draft of which was released by the NYDEC (the "*Draft SGEIS*") for review and comment. In addition, on April 23, 2010, the NYDEC announced that drilling operations proposed within the watersheds relied on by New York City and Syracuse for drinking water would be unable to utilize generic environmental impact statements and would therefore require full, case-by-case SEQR reviews.[276] The form of SGEIS was released for public comment in 2009. Observers consider the SGEIS regulations potentially to be the strictest in the country, and many of the provisions overlap with the proposed legislation described above. The review and comment period ended in December of 2009.[277] Then, on July 1, 2011, the New York Department of Environmental Conservation under Governor Cuomo issued the 2011 Preliminary Revised Draft Supplemental Generic Environmental Impact Statement (the "*Revised Draft SGEIS*"). The Revised Draft SGEIS has the effect of signaling that fracing will be allowed in New York following the public comments and the release of a final report.[278]

Key provisions of the Revised Draft SGEIS include prohibiting surface drilling (1) within 2,000 feet of public drinking water supplies; (2) on the state's 18 primary aquifers and within 500 feet of their boundaries; (3) within 500 feet of private wells, unless waived by the landowner; (4) in floodplains; (5) on principal aquifers without site-specific reviews; and (6) within the Syracuse and New York City watersheds.[279] The Department of Environmental

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[272] N.Y. STATE DEP'T OF ENVTL. CONSERVATION, FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 1 (1992), *available at* http://www.dec.ny.gov/docs/materials_minerals_pdf/fgeisexecsum.pdf (last visited July 7, 2011).

[273] The 1992 GEIS discusses hydraulic fracturing in the context of projects that**:** (i) require 80,000 gallons of fracturing fluid or less; (ii) were not located in the eastern portion of the state, near the New York City watershed infrastructure; and (iii) did not involve multiple wells drilled horizontally our of a single drilling pad. Anticipation of future projects that would exceed the scope of these factors was the primary reason why the DEC determined that a Supplemental Generic Environmental Impact Statement (discussed below) was needed. N.Y. STATE DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 3-2 (2009), *available at* http://www.dec.ny.gov/energy/58440.html (last visited July 7, 2011).

[274] *Id.* at 1-4.

[275] *Id.*; A supplement to generic environmental impact statement is required when any action may have environmental impacts that were not addressed in that statement. N.Y. COMP. CODES R. & REGS. tit. 6, 617.10(d)(4) (2011).

[276] Nick Malinowski, *NY Stiffens Rules for Fracking in Watersheds*, LAW360, Apr. 23, 2010, *available at* http://energy.law360.com/articles/164091 (last visited July 7, 2011).

[277] N.Y. STATE DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 3-2 (2009), *available at* http://www.dec.ny.gov/energy/58440.html (last visited July 7, 2011).

[278] *See* Mireya Navarro, *Drilling Into New York's Fracking Report*, N.Y. TIMES GREEN BLOG (July 8, 2011, 5:01 PM), http://green.blogs.nytimes.com/2011/07/08/drilling-into-new-yorks-fracking-report/.

[279] N.Y. STATE DEP'T OF ENVTL. CONSERVATION, FACT SHEET: 2011 RECOMMENDATIONS FOR PERMITTING HIGH-VOLUME HYDRAULIC FRACTURING IN NEW YORK STATE (2011), *available at* http://www.dec.ny.gov/docs/administration_pdf/sgeisfs072011.pdf (last visited July 27, 2011).

Conservation (DEC) claims that these proposed prohibitions will still permit more than 80 percent of the Marcellus Shale that is in New York to be developed.[280] The DEC also has named a 12-member Hydraulic Fracturing Advisory Panel.[281] The DEC also touts lessons learned from Pennsylvania's experience with hydraulic fracturing.[282]

Furthermore, when the Revised Draft SGEIS is adopted, additional standards will exist for SEQR of high-volume[283] fracing operations. These operations will require an additional addendum to the required environmental assessment form.[284] Such addendum will require information related to fracing including: depth of fracture zones; identification of proposed fracturing service companies and additive products; the proposed volume of fracing fluid and the percent (by weight) of water, types of proppants and any other additives; the source of the water to be used in the fracing fluid; distances to nearby water wells, reservoirs, wetlands, lakes or ponds, and occupied structures.[285] In addition, fluid disposal plans for fracing will require additional information regarding: the planned transport of the fracing fluid off of the well pad; the planned disposition of the fracturing fluid (*e.g.*, treatment facility, disposal well, reuse, centralize surface impoundment, etc.); identification and permit numbers for any proposed treatment facility or disposal well located in New York; and location and details of construction and operational information for any proposed centralized flowback water surface impoundment.[286]

Before Governor Cuomo took office in 2010, former Governor Paterson took several noteworthy actions regarding fracing. First, Paterson rejected the prospect of multi-state regulations promulgated by the Delaware River Authority, which he said would conflict with New York's approach that would include months of study and public comment before permitting drilling on the resultant regulations.[287] Second, Paterson vetoed a bill that would have imposed a sweeping moratorium on all new oil and gas drilling permits, and instead issued an executive order that imposed a seven-month moratorium limited to fracing horizontally drilled wells that

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280 *Id.*

281 N.Y. State Dep't of Envtl. Conservation, DEC Commissioner Appoints Members to Hydraulic Fracturing Advisory Panel (2011), ***available at*** http://www.dec.ny.gov/press/75416.html (last visited July 27, 2011).

282 N.Y. State Dep't of Envtl. Conservation, What We Learned From Pennsylvania (2011), *available at* http://www.dec.ny.gov/energy/75410.html (last visited July 27, 2011).

283 High-volume hydraulic fracturing will be defined based on the total amount of fracturing fluid used in all stages of the fracturing operation: more than 300,000 gallons is always considered high volume and all SGEIS and GEIS mitigation measures are required to be taken to satisfy SEQR. N.Y. State Dep't of Envtl. Conservation, Preliminary Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program 3-5 – 3-6 (2011), *available at* http://www.dec.ny.gov/data/dmn/ogprdsgeisfull.pdf (last visited July 25, 2011).

284 *Id*. at 3-9 – 3-10. In addition, additional locations will require site-specific SEQR. *Id.* at 3-15 – 3.17.

285 *Id*. at 3-9 – 3-12.

286 *Id*. at 3-12 – 3-13.

287 *See* Mireya Navarro, *N.Y. Objects to Release of Multistate Fracking Rules*, N.Y. Times Green Blog (Dec. 9, 2010, 5:53 PM), http://green.blogs.nytimes.com/2010/12/09/n-y-objects-to-release-of-multistate-fracking-rules/.

legally ended on July 1, 2011.[288]

On June 30, 2011, Governor Cuomo announced plans to eliminate the effective moratorium of fracing on privately-owned lands in New York, while keeping in effect the permit ban within the upstate watersheds of Syracuse and New York City, all state-owned lands, and within certain distances of aquifers used by other cities and towns.[289] It will most likely take months before the Governor's policy is codified by further draft NYDEC regulations.

Hydraulic fracturing operators must prepare a fluid disposal plan to pass the NYDEC's SEQR review and be issued a permit. Any well-drilling operation that involves a risk that brine, salt water[290] or other polluting fluids will be produced in sufficient quantities to be deleterious to the surrounding environment requires a fluid disposal plan to be submitted in addition to the standard drilling permit application.[291] Depending on the method of disposal chosen by the applicant, an additional disposal permit or an acceptable disposal contingency plan may be required.[292] Hydraulic fracturing operations must then also pass the SEQR (through compliance with the 1992 GEIS, or otherwise through a project-specific determination of environmental impact) as any other gas drilling project would.

Certain drilling fluids may be disposed of through use for road de-icing, dust suppression or road stabilization. Production brine from oil or gas wells may be used for road spreading purposes after the proper permit and beneficial use determination applications have been filed and approved.[293] However, fracing fluids obtained during flowback operations may not be spread on roads and must be disposed of in an authorized manner.[294]

North Dakota

North Dakota's Legislative Assembly has not enacted any legislation specific to hydraulic fracturing. The North Dakota legislature gave the North Dakota Industrial Commission (the "*NDIC*") jurisdiction and authority over all persons and property, public and private, necessary to enforce legislation related to oil and gas conservation, the development and production of subsurface minerals, coal exploration, and lignite research, among other matters.[295]

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288 *See* Mireya Navarro, *New York Governor Vetoes Fracking Bill*, N.Y. TIMES GREEN BLOG (Dec. 11, 2010, 7:35 PM), http://green.blogs.nytimes.com/2010/12/11/new-york-governor-vetoes-fracking-bill/.

289 Danny Kakim and Nicholas Confessore *Cuomo Will Seek to Lift Ban on Hydraulic Fracturing*, N.Y. Times, June 30, 2011. *Available at* http://www.nytimes.com/2011/07/01/nyregion/cuomo-will-seek-to-lift-drilling-ban.html?pagewanted=all (last visited August 9, 2011).

290 Brine and salt water are both defined to mean any water containing more than 250 parts per million of sodium chloride or 1,000 parts per million of total dissolved solids. N.Y. COMP. CODES R. & REGS. tit. 6, 551.2(at) (May 28, 1985).

291 N.Y. COMP. CODES R. & REGS. tit. 6, 554.1(c)(1) (Jan. 9, 1980).

292 N.Y. COMP. CODES R. & REGS. tit. 6, 554.1(c)(1) (Jan. 9, 1980).

293 N.Y. STATE DEP'T OF ENVTL. CONSERVATION, PRELIMINARY REVISED DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM Appendix 12 (2011), *available at* http://www.dec.ny.gov/data/dmn/ogprdsgeisfull.pdf (last visited July 25, 2011).

294 *Id.*

295 *Id*.

The NDIC has delegated the regulation of drilling and production of oil and gas to the Oil and Gas Division of the Department of Resources (the "*NDO&GD*").[296] The NDO&GD administers regulations of the drilling and plugging of wells, the restoration of drilling and production sites, the disposal of saltwater and oil field wastes, the spacing of wells, and the filing of reports on well location, drilling and production.[297] The NDO&GD is the administrative agency in North Dakota responsible for the enforcement of the rules and regulations that impact hydraulic fracturing.

Chapter 38-08 of the N.D. CENT. CODE regulates oil and gas resources, and vests the NDIC with the authority to require:

> The drilling, casing, operation, and plugging of wells in such manner as to prevent the escape of oil or gas out of one stratum into another, the intrusion of water into the oil or gas strata, the pollution of freshwater supplies by oil, gas or saltwater, and to prevent blowouts, cavings, seepages, and fires;[298] … [and] to regulate: [t]he drilling, producing, and plugging of wells, the restoration of drilling and production sites, and all other operations for the production of oil or gas … disposal of saltwater and oilfield wastes.[299]

As seen in other states, although North Dakota's regulations do not directly address hydraulic fracturing, certain regulations related to preparation of the well site, the preservation of strata, and construction and completion of the well bore, and post-completion methods may effect hydraulic fracturing.

Drilling, Well Site Construction and Reclamation. Prior to commencing drilling operations, an operator must apply for and obtain the requisite permit from the NDO&GD.[300] The application must include the target depth, estimated depth to the top of important biostratigraphic markers, estimated depth to the top of objective horizons, the proposed mud and casing program, including the size and weight thereof, the depth at which each casing string is to be set, the proposed pad layout (including cut and fill diagrams), and the proposed amount of cement for completion, including the estimated top of cement.[301] Recompletion of the well or drilling horizontally requires an additional application for permit.[302] The NDO&GD director has the authority to deny an application for a permit if the proposal would cause, or is reasonably believed to cause, waste or violate correlative rights.[303] The decision to deny such application

296 *See* North Dakota Oil and Gas Division *available at* https://www.dmr.nd.gov.oilgas/ (last visited July 7, 2011).
297 *See* North Dakota Industrial Commission *available at* http://www.nd.gov/ndic/ic-about.htm (last visited July 7, 2011).
298 N.D. CENT. CODE § 38-08-04(1)(c) (2011).
299 *Id.* § 38-08-04.2.a-e.
300 N.D. CENT. CODE § 38-08-05 (2010); N.D. ADMIN. CODE § 43-02-03-16 (2010).
301 N.D. ADMIN. CODE § 43-02-03-16 (2010).
302 *Id*.
303 *Id*.

may be appealed.[304]

The NDO&GD may require the drill site to be sloped and a dike built to divert surface drainage when necessary to prevent pollution of the land surface and freshwaters.[305] The law generally prohibits long-term storage of saltwater, drilling mud, oil or other contaminates in any pit or open receptacle except in an emergency.[306] However, to assure a supply of proper material or mud-laden fluid to confine oil, gas, or water to its native strata during the drilling of any well, each operator is required to provide a container or reserve pit to contain solids and fluids used and generated during well drilling and completion operations provided the pit can be constructed in a manner that prevents pollution of the land surface and freshwaters.[307] The reserve pit can only be used for drill cuttings and fluids used or recovered while actually drilling and completing the well.[308]

Generally, all waste associated with exploration or production of oil and gas other than drilling mud or drill cuttings must be properly disposed of in an authorized facility.[309] Water remaining in reserve pits must be removed and disposed of in an authorized disposal well or used in an approved manner.[310] The disposition of use of such water must be included on the notice that reports the reclamation plan.[311]

Casing, Tubing and Cementing Requirements. During the drilling of any oil or natural gas well, all oil, gas and water strata above the producing horizon must be sealed or separated where necessary to prevent their contents from passing into other strata.[312] An operator must shut off and exclude water from the penetrated oil-bearing and gas-bearing strata.[313] Water shutoffs are ordinarily made by cementing casing or landing casing with or without the use of mud-laden fluid.[314] The regulations prescribe specific casing, tubing and cementing requirements to "adequately protect and isolate all formations containing water, oil or gas or any combination of these; [and] protect the pipe through salt sections encountered … ."[315] When casing or cementing becomes defective, the operator must conduct tests to evaluate the condition of the well bore and

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304 *Id*.
305 N.D. ADMIN. CODE § 43-02-03-19 (2010).
306 N.D. ADMIN. CODE § 43-02-03-19.3 (2010) (such waste shall be removed from the pit or receptacle within 24 hours after being discovered and must be disposed of at an authorized facility).
307 N.D. ADMIN. CODE § 43-02-03-19 (2010).
308 *Id*.
309 N.D. ADMIN. CODE § 43-02-03-19.2 (2010).
310 *Id*.
311 *Id*.
312 N.D. ADMIN. CODE § 43-02-03-20 (2011). The regulation further provides that "[a]ll freshwaters and waters of present or probable value for domestic, commercial, or stock purposes shall be confined to their respective strata and shall be adequately protected by methods approved by [the Division]. Special precautions shall be taken in drilling and plugging wells to guard against any loss of artesian water from the strata in which it occurs and the contamination of artesian water by objectionable water, oil, or gas."
313 *Id*.
314 *Id*.
315 *Id.* § 43-02-03-21.

correct the defect, or, if the defect is irreparable, the operator must plug the well bore.[316]

The NDO&GD director may prescribe pretreatment casing pressure testing or other operational requirements designed to protect wellhead and casing strings during treatment operations.[317] When damage results from perforating, fracturing, or chemically treating a well, the operator must immediately notify the NDO&GD director and proceed with diligence to use the appropriate method and means for rectifying such damage.[318] If the damage cannot be undone, the NDO&GD director may order the operator to plug the well.[319]

Release Notifications. In the event fracing results in a fire, leak, spill or blowout, the operator verbally notify the NDO&GD director within twenty-four (24) hours of discovery of the fire, leak, spill or blowout.[320] In addition to providing notice to the NDO&GD director, the operator must also notify the surface owners.[321] Verbal notification must be followed by a written report within ten days after cleanup of the incident.[322]

Injection Control. Within the larger Department of Resources, the Division of Water Quality administers the standards and rules related to the Ground Water Protection Program.[323] The Ground Water Protection Program includes regulations that govern underground injection.[324] The Underground Injection Control Program classifies injection wells.[325] In turn, "Underground injection" is defined to mean the "subsurface emplacement of fluids…which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production … unless those waters are classified as a hazardous waste at the time of injection…For enhanced recovery of oil or natural gas … .[326] The regulations specifically prohibit any "[u]nderground injection that causes or allows movement of fluid into an underground source of drinking water."[327] An underground injection may not be conducted without first obtaining a permit from the NDO&GD after notice and hearing.[328]

Finally, in addition to the regulatory scheme administered by the NDO&GD, North Dakota's legislature enacted laws to control, prevent and abate pollution of North Dakota's waters.[329] The law defines "waters of the state" to include "other bodies or accumulations of water on or under the surface of the earth."[330] To advance the policy of the state to protect and maintain its waters, the law created a state water pollution control board to advise the state

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316 *Id.* § 43-02-03-22.
317 *Id.* § 43-02-03-27.
318 *Id.*
319 *Id.*
320 *Id.* § 43-02-03-30.
321 *Id.*
322 *Id.*
323 *See* Division of Water Quality website at http://www.ndhealth.gov/WQ/ (last visited July 7, 2011).
324 N.D. CENT. CODE § 61-28-02 (2011).
325 *Id.*
326 N.D. ADMIN. CODE § 43-02-05-01.
327 *Id.* § 43-02-05-02.
328 *Id.* § 43-02-05-04.
329 N.D. CENT. CODE § 61-28.
330 *Id.* § 61-28-02.

department of health with regard to water pollution issues.[331] In addition, the North Dakota state department of health is vested with the broad authority to "develop comprehensive programs for the prevention, control, and abatement of new or existing pollution of the water of the state"[332]

<u>Ohio</u>

Ohio statutes give the Division of Mineral Resources Management (the "*OHDMR*"), a branch of the Ohio Department of Natural Resources, "the sole and exclusive authority to regulate the permitting, location, and spacing of oil and gas wells and production operations within the state."[333] The Chief of the OHDMR (the "*DMR Chief*"), creates the rules for administration, implementation, and enforcement of the state's oil and gas laws.[334]

Current Ohio Fracing Law: New statutory revisions effective July 1, 2010 include provisions that directly affect fracing.[335] In addition, many of the laws regulating development of minerals generally also apply to fracing operations. Both the existing framework and the new statutory changes focus on safety requirements for drilling operations and protecting the integrity of potable water.

The current statute and administrative rules affect oil and gas developers engaged in fracing by heavily regulating the injection of saltwater, the fluid most commonly used in fracing. Currently, the only substantive statutory regulations explicitly affecting fracing are the waste disposal requirements applicable to all well production and notification procedures for wells employing fracing.[336] The statute indirectly regulates fracing, however, by requiring the DMR Chief to issue a permit before any operator may inject saltwater as a part of "secondary or additional recovery operations."[337] The permit may not be issued for injection of fluids unless the DMR Chief concludes that:

> the applicant has demonstrated that the injection will not result in the presence of any contaminant in underground water that supplies or can be reasonably expected to supply any public water system, such that the presence of any such contaminant may result in the system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons.[338]

The Administrative Code provides further guidelines for injecting fluids to aid in recovery by imposing numerous regulations for saltwater injection or brine injection wells.

[331] *Id.* § 61-28-03.
[332] *Id.* § 61-28-04.
[333] OHIO REV. CODE ANN. § 1509.02 (2011).
[334] *Id.* § 1509.03.
[335] *See* OHIO REV. CODE ANN. §§ 1509.10, 1509.17, 1509.19, 1509.22 (effective June 30, 2010).
[336] *Id*. §§ 1509.19, 1509.22 (2011).
[337] *Id.* § 1509.21 (2011).
[338] *Id*.

Specifically, each saltwater injection well must meet specific construction and permit requirements.[339] These requirements include that the surface casing be free of apparent defects and set at least fifty (50) feet below the deepest underground source of potentially potable water and that the well be inspected before initial injection.[340] A variance from these and other requirements may be obtained only if the volume of injection is sufficiently low and the DMR then makes the required statutory determination that fluid injection will not contaminate underground public water supplies.[341] In addition, no saltwater injection well may be drilled within one hundred feet of an occupied private dwelling.[342]

Before using a well for brine injection, an operator must obtain a permit from the OHDMR subject to approval from the DMR Chief.[343] The application for a permit must describe the casing in detail, include a map of the area (including the location of other wells), and must be accompanied by a notice to be filed with the OHDMR.[344] After the notice has been on file for fifteen days, the DMR then grants the permit provided it complies with regulatory requirements and no objections have been filed.[345]

The DMR Chief imposes additional operating requirements and reporting requirements on saltwater injection wells. First, operators may only inject saltwater or "standard well treatment fluid" into a well approved under the Administrative Code and may only do so up to a certain pressure.[346] Also, injection pressures, volumes, and annular pressure must be measured, and reports of the results must be submitted in a form supplied by the OHDMR once a year.[347]

2010 Fracing Revisions: The 128th General Assembly and the Governor of Ohio approved changes effective July, 2010. These changes include provisions which directly address fracturing.

First, the new statute defines "well stimulation" as "the process of enhancing well productivity, including hydraulic fracturing operations."[348] The statute creates new reporting and substantive requirements for activities relating to "well stimulation." Under the new law, within sixty (60) days of completing drilling operations to the proposed total depth of a well or discovery of a dry hole, the driller must file a well completion record[349] on a form approved by the DMR Chief. Among other details, the record needs to provide information about "the type and volume of fluid used to stimulate the reservoir of the well, the reservoir breakdown pressure, the method used for the containment of fluids recovered from the fracturing of the well, the methods used for the containment of fluids when pulled from the wellbore from swabbing the

339 OHIO ADMIN. CODE §§ 1501:9-3-05 to 9-3-06 (2009).
340 *Id.* § 1501:9-3-05.
341 *Id.*
342 *Id.* § 1501:9-3-09.
343 *Id.* §§ 1501:9-3-06(A), 9-3-12.
344 *Id.* § 1501:9-3-06(B)-(E).
345 *Id.* § 1501:9-3-06(E)(2).
346 *Id.* § 1501:9-3-07(C)-(D).
347 *Id.* § 1501:9-3-07(E)-(F).
348 OHIO REV. CODE ANN. § 1509.01 (effective June 30, 2010).
349 The current statute requires a report within sixty days of "well completion."

well, the average pumping rate of the well, and the name of the person that performed the well stimulation." In addition, the driller needs to include a copy of the log from the stimulation of the well, a copy of the invoice for each of the procedures and methods used on a well, and a copy of the pumping pressure and rate graphs.[350]

Aside from reporting requirements, the statute now explicitly requires the DMR Chief's written authorization before allowing "well perforation for purposes of stimulation in any zone that is located around casing that protects underground sources of drinking water."[351] In addition, new Ohio regulations require that pits or steel tanks to be used for "brine and other waste substances resulting from, obtained from, or produced in connection with drilling," be constructed and maintained to prevent the escape of brine and other waste substances, as authorized by the chief of DMR. New statutes and regulations also impose restrictions on location of drilling with respect to distance of the site of drilling from an occupied dwelling or urban area.

<u>Oklahoma</u>

Oklahoma oil and gas regulations are promulgated and enforced by the Oklahoma Corporation Commission (the "*OCC*"), a constitutional agency,[352] through its Oil and Gas Conservation Division (the "*OGCD*").[353] The OCC rules and regulations are found in Title 165 of the Oklahoma Administrative Code (the "*OAC*").[354]

Hydraulic fracing has been used for over sixty (60) years in Oklahoma and is currently more highly regulated than in most states. The general rule concerning fracing fluid states "[i]n the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface and subsurface fresh water."[355]

More specific management of fracing operations is found throughout the OAC. OAC § 165:10-3-3 through 10-3-4 regulate surface and production casing.[356] Specifically, § 165:10-3-3 requires operators to report any event of rupture, break, or opening that occurs in the surface or production casing. Regulations also govern the use of commercial and noncommercial pits[357] as

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350 *Id.* § 1509.10(A)(9).

351 *Id.* § 1509.17(A).

352 "The Corporate Commission was established in 1907 by Article 9 of the Oklahoma Constitution…." *See Oklahoma Corporation Commission History*, http://www.occeweb.com/Comm/commissionhist.htm (last visited July 6, 2011).

353 *See* Oklahoma Corporate Commission, http://www.occ.state.ok.us (last visited March 31, 2010); *see also* Oil and Conservation Division, http://www.occ.state.ok.us/Divisions/OG/newweb/og.htm (last visited March 31, 2010).

354 OKLA. ADMIN. CODE § 165 (2010). Specifically, the oil and gas regulations are found in Title 165, Chapter 10 of the OAC.

355 OKLA. ADMIN. CODE § 165:10-3-10 (2010).

356 *Id*. §§ 165:10-3-3 to -4 (2010).

357 *See* OKLA. ADMIN. CODE §§ 165:10-7 to -9 (2010).

well as plugging and abandonment.[358]

The OCC has adopted Oklahoma's water quality standards[359] established by the Oklahoma Water Resources Board.[360] Generally, OAC § 165:10-7-5 requires that "[a]ll operators, contractors, drillers, service companies, pit operators, transporters, pipeline companies, or other persons shall at all times conduct their operations in a manner that will not cause pollution."[361] The same section also provides rules regarding reporting of non-permitted discharges.[362] Municipalities or other governmental subdivisions may also submit an application to the OCC requesting it to execute an order establishing special field rules within a particular area to protect and preserve fresh water supplies.[363]

In March 2010, the OCC submitted proposed amendments regarding its existing fracing rule to the Oklahoma legislature**.** These proposed amendments have since passed, and include a provision providing a cross-reference to existing rules that affect the management of fracing operations. The amendments also establish procedures for flowback water pits with capacity in excess of 50,000 barrels and new requirements for commercial recycling facilities.[364]

Pennsylvania

The Pennsylvania Bureau of Oil and Gas Management, a subdivision of the Pennsylvania Department of Environmental Protection (the "*DEP*"), oversees creation and enforcement of regulations related to exploration, development, and recovery of oil and gas resources in that state.[365] The Bureau of Oil and Gas Management has this authority pursuant to Pennsylvania's Oil and Gas Act.[366] As one of the original oil and gas producing states—oil has been extracted in the state since the middle of the 19th century—Pennsylvania has a well-developed system of common and statutory laws concerning oil and gas production, although much of the pertinent case law is over a century old**.** Despite the maturity and sophistication of the Pennsylvania oil and gas legal regime, there were, until recently, practically no existing regulations that specifically targeted recovery through hydraulic fracturing.

On January 28, 2010, Governor Ed Rendell proposed amendments to existing drilling regulations that specifically affect the use of hydraulic fracturing. The governor also proposed the hiring of sixty-eight (68) inspectors to enforce the new rules.[367]

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358 *Id.* § 165:10-11.
359 OKLA. ADMIN. CODE § 165:10-7-4 (2010).
360 The Oklahoma Water Quality Standards are published in OKLA. ADMIN. CODE § 785:45 (2010).
361 OKLA. ADMIN. CODE § 165:10-7-5 (2010).
362 *Id.* at 10-7-5(c).
363 *Id.* § 165:10-7-6.
364 *Id.* § 165:10-7-16(f), :10-9-4.
365 See Oil & Gas Programs, Pennsylvania Department of Environmental Protection *available at* http://www.depweb.state.pa.us/portal/server.pt/community/oil___gas/6003 (last visited July 7, 2011).
366 58 PA. STAT ANN. § 601, *et seq.* (2011).
367 Hurdle, Jon, *Pennsylvania Plans More Gas Drilling Regulation*, REUTERS (Jan. 28, 2010), *available at* http://www.reuters.com/article/idUSN2812147220100128 (last visited July 7, 2011).

The proposed rules—which were ultimately passed and became effective on February 5, 2011—are almost entirely devoted to protecting water supplies.[368] Contamination of water supplies is commonly used as a basis for arguing that hydraulic fracturing should be limited or prohibited. The amendments both strengthen the requirements for constructing well casing[369] and impose a stricter obligation on operators to replace any water supplies they contaminate.[370]

The regulatory amendments also add a general requirement that the operator shall construct and operate the well to "ensure that the integrity of the well is maintained and health, safety, environment and property are protected."[371] Specifically, the operator is required to prevent "brine, completion and servicing fluids, and any other fluids or materials from below the casing seat from entering fresh groundwater"[372] Additionally, the operator is required to prepare and maintain a "casing and cementing plan" that describes how the well will be drilled and completed in compliance with the new regulations.[373] This plan must contain information regarding "anticipated fresh groundwater zones"[374] and "casing type, depth, diameter, wall thickness and burst pressure rating."[375] A copy of the plan must be kept at the well site for review by authorities.[376]

In the event that the casing and cementing plan fails, resulting in contamination of groundwater, regulations concerning replacement of the water supply activate. The regulations already contain a general requirement that a well operator who contaminates or diminishes a water supply "replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply."[377] The proposed amendments, however, seek to add some specificity to this existing obligation. The new rules specify what it means for a replacement water supply to be of "adequate quantity" and "adequate quality." To be of adequate quantity, the replacement water supply must (i) deliver enough water to meet the user's needs or (ii) connect to a public water system that supplies enough water to meet the user's need.[378] To be of adequate quality, the replacement water supply must (i) meet the standards established pursuant to the Pennsylvania Safe Drinking Water Act or (ii) be of comparable quality to the prior water supply, if the prior water supply did not meet the Water Act standards.[379]

On June 23, 2010, several Pennsylvania State Senators introduced a bill calling for the creation of an Emergency Drinking Water Support Fund.[380] The bill was referred to the Environmental Resources and Energy Committee, and subsequently reintroduced the following

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368 Advanced Notice of Proposed Rulemaking, 25 PA. CODE § 78 Oil and Gas Wells, *available at* http://tjogel.org/wp-content/uploads/2009/10/King_Final.pdf (last visited July 7, 2011).

369 25 PA CODE § 78.73, *et seq*. (2011).

370 *Id*. § 78.51, *et seq*.

371 *Id*. § 78.73(a).

372 *Id*. § 78.73(b).

373 *Id*. § 78.83a(a).

374 *Id*. § 78.83a(a)(1).

375 *Id*. § 78.83a(a)(3).

376 *Id*. § 78.83a(b).

377 *Id*. § 78.51(a).

378 *Id*. § 78.51(d)(3).

379 *Id*. § 78.51(d)(2).

380 S.B. 1416, 194th Sess. (Pa. 2010).

year.[381] The legislation would impose a $10 surcharge for every well permit.[382] That surcharge would accumulate in a fund, which would be used for "the testing of well water and purchasing of clean water for residents and businesses that have reason to believe their well water is contaminated from either an accidental spill of fracing water or chemicals, seepage of chemicals and fracing water or seepage of natural gas dislodged by the fracing process."[383] New legislation has been also been proposed to require more extensive environmental studies before Pennsylvania issues a drilling permit.[384] That same bill proposes to implement a fracing buffer zone, whereby fracing may not take place "within 3,000 feet of a reservoir that serves as a water source for a community water system," and would require each fracing operator to report the chemicals used in their fracing fluid.[385]

In addition to increased state-level regulation, operators are also finding themselves subject to new county and local government rules. For instance, Cecil Township in Washington County, Pennsylvania is in the process of enacting a zoning ordinance that treats all oil and gas development as a "conditional use" of land, meaning that the activity must be approved by the Cecil Township Board of Supervisors.[386] A number of Pennsylvania counties are becoming increasingly organized in their response to the increased drilling activity. For instance, Wayne County created an Oil and Gas Taskforce.[387] The mission statement of this taskforce is to "identify key issues, research facts, information, and review and provide public education regarding the economic, environmental and community impacts of oil and gas exploration of the Marcellus Shale in Wayne County."[388]

Despite the infancy of hydraulic fracturing laws and regulations in Pennsylvania, both state and federal environmental agencies have gone after various players in the Marcellus Shale, such as Cabot Oil & Gas. When water supplies near Cabot wells were found to be contaminated with methane, the DEP ordered Cabot to fix cement well casings in the area by March 31, 2010.[389] Cabot failed to meet this deadline and, consequently, was fined $240,000 and prohibited from drilling new wells in the area for one year.[390] As a result of these events, Senator Bob Casey called on the U.S. Environmental Protection Agency to conduct an investigation on the impact of hydraulic fracturing on water sources in Pennsylvania.[391] As the use of fracing increases in Pennsylvania, interested parties should expect regulation and oversight by localities to grow correspondingly.

Texas

381 S.B. 596, 195th Sess. (Pa. 2011).

382 *Id.*

383 *Id.*

384 H.B. 2630, 194th Sess. (Pa. 2010).

385 *Id.*

386 Proposed Ordinance of the Township of Cecil, Washington County, Pennsylvania, Providing for the Regulation and Zoning of Oil and Gas Drilling Operations, *available at* http://www.marcellus-shale.us/pdf/Cecil-Drill-Ord.pdf (last visited April 5, 2010).

387 Oil and Gas Taskforce, *available at* http://wcpaoilandgastaskforce.info/ (last visited July 7, 2011).

388 *Id*.

389 Allison, Jocelyn, *Cabot Ordered to Plug Wells in Pa. Pollution Probe*, LAW 360 (April 16, 2010).

390 *Id*.

391 Meyer, Elaine, *EPA Urged to Probe Fracking Water Pollution in Pa.*, LAW 360 (April 27, 2010).

Regulations that Specifically Affect Fracking. In 2011, the Texas legislature and the Texas Railroad Commission, the state's primary industry regulator, have each taken steps to enhance the regulatory regime for fracing. Since 1977, the Sunset Advisory Commission (the "SAC") has been charged with examining state agencies in an effort to eliminate repetitive or duplicative efforts, waste and inefficiency. On a rotating basis, each state agency is examined over three to eight months during periods when the state legislature is not in session. Despite the name of the commission, the SAC is not only tasked with determining whether agencies under consideration should be merged or eliminated, but also to promote efficiency of coverage and streamlining of existing regulatory efforts both within and between agencies. Once the SAC has compiled its recommendations for a particular agency, the legislature then can promulgate laws to implement the changes the SAC has recommended for the agency to achieve its objectives.

Before the 2011 legislation session, the SAC reviewed twenty-eight Texas agencies including the Texas Commission on Environmental Quality (the "TCEQ"), the Railroad Commission of Texas (the "RRC") and the Texas Water Development Board (the "TWDB").[392] From SAC's recommendations, various bills were introduced that altered the structure and mission of these four agencies. Bills covering changes to the TCEQ and the TWDB passed while all bills altering the RRC failed.

While the RRC is the primary regulator of oil and gas operations, other agencies' regulations can affect operations. From a substantive perspective, the TCEQ's jurisdiction over oil and gas production activities is generally limited to regulation of air quality; the RRC regulates virtually all other environmental aspects of oil and gas operations, including those that affect water quality. The TCEQ regulates surface water appropriation, however, while groundwater appropriation is not directly regulated by any state agency and is subject to the rule of capture, though that common law rule has been largely preempted in most areas of the state by ground water management districts that are authorized to allocate water based on equitable considerations.

Railroad Commission of Texas. In May 2011, Texas legislators passed an amendment, signed by the Texas governor in June, to make the state one of the first to require operators by law to disclose the chemicals used in their fracing fluids (so long as doing so would not reveal trade secrets).[393] Prior to this amendment, however, fracing was not formally regulated in Texas.[394] Under the new law, passed with broad industry support, well operators are required to "complete the form posted on the hydraulic fracturing chemical registry Internet website of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission" with respect to the well in which fracing fluids are used. The required disclosure includes both the volume of

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392 Press Release, TCEQ, Summary of Sunset Legislation, (Sep. 2011), *available at* http://www.sunset.state.tx.us/legislation11.htm (last visited Nov. 21, 2011).

393 H.B. 3328, 82d Leg., R.S. (Tex. 2011).

394 *See Coastal Oil & Gas Corp. v. Garza Energy Trust*, 268 S.W.3d 1, 17 (Tex. 2008) ("Though hydraulic fracturing has been commonplace in the oil and gas industry for over sixty years, neither the Legislature nor the [RRC] has ever seen fit to regulate it, though every other aspect of production has been thoroughly regulated. Into so settled a regime the common law need not thrust itself."); ERNEST E. SMITH & JACQUELINE LANG WEAVER, 3 TEXAS LAW OF OIL AND GAS, §14.4(B) at 14-74 (2d. Ed. 2009) ("The Railroad commission has not yet taken any action to assert jurisdiction over hydraulic fracturing.").

water used and the chemical ingredients of the fracturing fluids used. The referenced website, fracfocus.org, has been operating for some time and is available for operators to post data about the chemical composition of their fracing fluids. However, an operator will be able to withhold from disclosure information for which it claims trade secret protections, but affected property owners and neighbors to the property owners will be able to challenge the trade secret designation. In addition, a means will be provided to supply the information to health professionals and emergency responders in case of an injury or other accident. While the statute became effective on September 1, 2011, the law provided that the RRC must adopt implementing regulations before the statute's requirements become mandatory. The statute expressly provides that it "applies only to a hydraulic fracturing treatment performed on a well for which an initial drilling permit is issued on or after the date the initial rules adopted by the Railroad Commission of Texas under [the hydraulic fracing] subchapter take effect."

On August 22, 2011, the RRC responded to the call of the state legislature, releasing proposed new hydraulic fracturing chemical disclosure requirements and asking for public comment. After a 30-day comment period ending October 11, 2011, and public hearing on October 5, 2011, the RRC recalibrated the law in response to comment and released the final regulation governing fracing fluid disclosure on December 13, 2011 to be effective, as stipulated by the enacting legislation, immediately.

The new regulations provide for mandatory disclosure of fracing fluids on the publically-available website "FracFocus.org"—a internet archive jointly maintained by the Interstate Oil and Gas Compact Commission and the Groundwater Protection Council.[395] Specifically, as soon as possible, but within fifteen (15) days of completing the fracing treatment, the supplier and service companies who provide a wellsite with fracing fluid must disclose to the operator of record the trade name and initial supplier of each additive, along with a brief description of the intended use of each additive.[396] In addition, the supplier or service company must disclose to the operator any chemical ingredient subject to the requirements of 29 CFR 1910.1200(g)(2)—the hazard communication rules which describe what information is disclosed on OSHA Material Safety Data Sheets.

Subsequently, the operator is required to submit the information compiled about the chemical ingredients of the fracing fluid used in its operations to be posted publically via FracFocus (or similar outlet).[397] This disclosure, the "Chemical Disclosure Registry" form, provides details concerning the following:

(1) operator identity;

(2) date of fracing;

(3) county, API number, longitude/latitude of the well and depth;

(4) volume of water (or other fluid) use for fracing;

[395] *See* 16 TEX. ADMIN. CODE §§ 3.29(a-h) (2011)
[396] 16 TEX. ADMIN. CODE § 3.29(c)(1) (2011)
[397] 16 TEX. ADMIN. CODE § 3.29(c)(2)(A) (2011)

(5) each additive used in the fracing process, their trade names, supplier, and a brief (one line or so) description of the intended use or function of each additive;

(6) each ingredient used in the fracing that is subject to the requirements of 29 C.F.R. § 1910.1200(g)(2), as provided by the chemical supplier, service company, or operator (if the operator provides its own chemical ingredients). 29 C.F.R. § 1910.1200(g)(2), in turn, details the chemicals which must be described on "material data sheets" as required by the Occupational Safety and Health Administration;[398]

(7) all chemical ingredients added by operator; and

(8) the actual or maximum concentration of each chemical ingredient disclosed per items 5, 6 and 7 on this list.

The Chemical Disclosure Registry form must then be submitted to the RRC along with the well completion report, along with a supplemental list of all chemicals and their respective CAS numbers that weren't disclosed on the Chemical Disclosure Registry form.

Under the new RRC regulations, the operator, supplier or service company is not required to disclose ingredients that are, in turn, not disclosed by the manufacturer, supplier or service company or ingredients not intentionally added to the fracing fluid or which occur incidentally or unintentionally in trace amounts.[399] The rules also provide that if the chemical ingredients of the additives are entitled to protection as trade secret information pursuant to the Texas Government Code, Chapter 552, then disclosure may not be required, provided the trade secret claim is made clear on the Chemical Disclosure Registry form.[400]

In addition, the proposals provide that the trade secret exception may be challenged within two years of the filing of the final well completion report by landowners upon whose land the well is located or whose land is adjacent[401] to the well, or a state agency with jurisdiction over a matter to which the claimed trade secret information is relevant.[402] A proposed form for such a challenge was included in the proposed regulations. If a health profession and/or emergency responder is related confidential information concerning fracing chemicals, all such information must be kept confidential except to the extent necessary to perform his duties.[403]

Texas Commission on Environmental Quality. Use of surface water is regulated by the TCEQ. The recommendations of the SAC for the TCEQ were codified and passed the Texas

398 Chemical manufacturers and importers are required to obtain or develop a material safety data sheet for each hazardous chemical they produce or import. Material safety data sheets are required to be available for rig personnel.

399 16 TEX. ADMIN. CODE § 3.29(d) (2011) (An example of such an incidental presence would be substances which arise as a result of chemical reactions in the ground.)

400 16 TEX. ADMIN. CODE § 3.29(e) (2011)

401 We note that "adjacent" is not defined in the disclosure regulation.

402 16 TEX. ADMIN. CODE § 3.29(f) (2011)

403 16 TEX. ADMIN. CODE § 3.29(g) (2011)

legislature.[404] Thought to be some of the most influential Texas environmental laws passed in 2011, House Bill 2694 again authorizes the TCEQ to operate for another twelve years. It also addresses other procedural and substantive changes in TCEQ operations and powers.

Generally, the new law is designed to provide more transparency to the public about the TCEQ's actions (or inaction) and its plans to assess and respond to public concern about matters related to TCEQ control. Specifically, the law modifies various portions of the Texas Water Code (§ 5.239, § 5.271 and §5.276) in an attempt to make the TCEQ more responsive to public concern and requires performance reports from the Office of Public Interest Counsel to be given annually to the TCEQ regarding its representation of the public interest in matters before the TCEQ.[405]

Changes were also made to elucidate the exact power of the TCEQ director to affect water use during drought. House Bill 2694 adds § 11.053 to the Water Code, which authorizes the TCEQ director to mandate temporary interruption or modification of a water right use during drought conditions. A TCEQ director's order of suspension of a water right must be designed to maximize the beneficial use of the water and minimize waste and the impact on water right holders to develop.[406] It must also consider efforts by the owners of the suspended water right to design and employ their own water conservation and drought contingency schemes as required by Chapter 11 of the Water Code.[407] The TCEQ director's suspension or alteration of a water right cannot require the release of water stored under a water right.[408]

In order to promulgate these rules, the TCEQ has been directed to define what a "drought" and a "water shortage" is and the circumstances under which the new suspension powers may be invoked and how long the suspension may last, along with the usual administrative processes of notice, hearing, comment and appeals procedures. The SAC recommended that records of water use be required to be kept by water right owners, and the bill requires that water right owners keep a monthly record of the water right use which can be reviewed by the TCEQ upon declaration of a "drought" or "water shortage."[409]

Rules associated with all these portions of the TCEQ SAC law are currently being formulated and proposed. Stakeholder meetings, public hearings and comment periods for same

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404 As codified in TEX. WATER CODE ANN. § 36.117 (Vernon 2011) (review of legislative information related to bill passage *available at* http://tx.opengovernment.org/sessions/82/bills/sb-692 (last visited Nov. 19, 2011)).

405 Emily Rogers, *Update: TCEQ and the Texas Water Development Board,* 6TH ANNUAL ADVANCED TEXAS ADMINISTRATIVE LAW SEMINAR, August 25-26, 2011, Austin, Texas, at 2-3, *available at* http://www.bickerstaff.com/files/Update._TCEQ_and_the_Texas_Water_Development_Board___for_web_site___2011__00557755_.PDF (last visited Oct. 10, 2011)(This presentation provides an outstandingly detailed description of every SAC recommendation and the corresponding 2011 changes to the laws covering the TCEQ and TWDB.)

406 House Bill 2694 (§ 5.03)

407 *Id*.

408 *Id*.

409 House Bill 2694 (§ 5.02(d-e)).

will continue through late 2011 and early 2012.[410]

The TCEQ continues to respond to the drought. More "senior" water rights (*i.e.* those established and recognized by the state first) are allowed "first draw" rights during times of drought while more "junior" water rights (*i.e.* the most recently issued permits) may be suspended, altered or curtailed by the TCEQ by priority date. For example, on November 14, 2011, in response to lowered watershed measurements, the director of the TCEQ notified certain Neches River Basin "junior" water-permit owners that their right to divert the river's water has been temporarily but immediately suspended.[411] Suspended water rights include those with a priority date of Aug. 13, 1913 or later, term, and temporary water-right permits in the Neches River Basin. Water rights associated with municipal uses or for power generation have not been suspended. Land owners with property adjacent to watercourses in the Neches River Basin may continue to divert water for domestic and livestock/poultry use, however, because of riparian rights. This restriction follows similar restrictions in 2011 placed on permit rights affecting water draws from the San Saba, Llano and Brazos rivers, among other surface water sources.[412]

Texas Water Development Board. Although the SAC-sourced bill covering the TWDB passed,[413] little that was changed in the TWDB's scope and activities will have a direct impact on oil and gas operations[414] because of (1) the exception is Chapter 36 of the Texas Water Code[415] which generally excepts oil and gas operations from oversight related to groundwater use and (2) the purpose and activities of the TWDB. The TWDB's primary concern is administering the Texas Water Bank, established in 1993 to help communities transfer, sell or lease water rights and where water rights are held for environmental flow maintenance purposes. The TWDB also currently provides scientific assistance through modeling to communities planning future water use and conservation.

Groundwater Management Districts. Groundwater appropriation is generally subject to ground water management districts that are authorized to allocate such water based on equitable considerations. Though the state water code exempts oil and gas drilling from some rules enacted by groundwater districts, changes in the Water Code and the perceived difference between

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410 TCEQ maintains a repository of the steps which are underway for rulemaking available at http://www.tceq.texas.gov/rules/propose_adopt.html (last visited Nov. 20, 2011).

411 Press Release, TCEQ Restricts Junior Water Rights, TCEQ, Nov. 14, 2011, *available at* http://www.tceq.texas.gov/news/releases/111411droughtnecheslnvacall (last visited Nov. 20, 2011).

412 Various TCEQ press releases related to river water permit restrictions, *available at* http://www.tceq.texas.gov/news/aggregator/atct_topic_view?b_start:int=20&-C= (last visited Nov. 20, 2011).

413 As codified in TEX. WATER CODE ANN. § 15.975 (Vernon 2011) (review of legislative information related to bill 370 passage *available at* http://tx.opengovernment.org/sessions/82/bills/sb-370 (last visited Nov. 19, 2011)).

414 The fracing fluid disclosure legislation, discussed below, was attached as an amendment to the TWDB's 2011 SAC bill. This portion of the legislation will, of course, have a significant impact on oil and gas operations in Texas, but is unrelated to the activities of the TWDB and, in fact, almost caused the larger TWDB SAC bill which encompassed it to fail. (Source: Telephone Interview with Wendy Foster, Director of Government Relations, TWDB (Nov. 8, 2011).

415 TEX. WATER CODE ANN. § 36.117 (Vernon 2011).

drilling and fracing are being seen by conservation districts as excepting fracing operations from the larger permit exception for groundwater used in drilling and exploration.

Currently, Section 117 of Chapter 36 of the Texas Code provides that a water conversancy district in Texas must provide an exception for any requirement by the district for a permit to drill a "water well used solely to supply water for a rig that is actively *engaged in drilling or exploration operations* for an oil or gas well permitted by the [RRC] provided that the person holding the permit is responsible for drilling and operating the water well."[416] Until recently, this exception kept groundwater districts from permitting and (through permitting) curtailing the use of groundwater for oil and gas operations, including fracing.[417]

Partially because of increased fracing operations and the current drought, this stance is changing, primarily through subtle changes in Section 117 of Chapter 36 wrought by the 2011 Legislature via SB 692 and a tighter reading of the statutes.[418] For example, conservancy districts are now distinguishing "drilling or exploration operations" from fracing operations, and may require permitting for the second type of use. [419] Fracing is being seen by water districts as a process separate from drilling and which should therefore be subject to the new water limits.[420] Support for this interpretation can be found in Section 117 of the Water Code. For example, if the groundwater used that is exempted from permitting by this exception is no longer used solely to supply water for a drilling rig that is actively engaged in oil and gas drilling or exploration operations, the permitting exception ends—but hydraulic fracturing or secondary/tertiary recovery operations may not be included in "drilling or exploration" operations. In addition, while water districts may not restrict the production from wells used for providing water to livestock or poultry, no such express exemption exists

Conservancy districts from around Texas are moving forward with regulation and curtailment of the use of groundwater for fracing operations. For example, the city of Grand Prairie, which is located on the eastern boundary of the Barnett Shale in (primarily) Dallas County, Texas, became in August 2011 the first municipality in Texas to ban the use of city water for fracing. [421] In July, 2011, conservancy officials for the southernmost portions of the Ogallala Aquifer, which is located in the Permian Basin near Midland/Odessa, expressly included water used for hydraulic fracturing when they approved the district's first-ever restrictions on water use.[422] The Evergreen Underground Water Conservation District, which directs aquifer use for Atascosa, Frio, Karnes and Wilson Counties in South Texas, applied their

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416 TEX. WATER CODE ANN. § 36.117(b)(2) (Vernon 2011) (emphasis added).

417 Telephone Interview with Jim Conkwright, Director, High Plains Underground Water Conservation District No. 1, Lubbock, Texas (Nov. 8, 2011).

418 Telephone Interview with Brian Sledge, Attorney, Government Relations Practice Group Chairman, Lloyd Gosselink Rochelle & Townsend, P.C., Austin, Texas (Nov. 8, 2011).

419 *Id*.

420 *Id*.

421 Mike Lee, *Parched Texans Impose Water-Use Limits for Fracking Gas Wells*, BLOOMBERG BUSINESSWEEK (Oct. 6, 2011) available at http://www.businessweek.com/news/2011-10-06/parched-texans-impose-water-use-limits-for-fracking-gas-wells.html (last visited Nov. 6, 2011).

422 *Id*.

preexisting water use limits to hydraulic fracturing in 2008.[423] Others are considering similar action in the future. For example, Janet Guthrie, general manager of the Hemphill County Underground Water Conservation District in North Texas, suggested water limits may be imposed for use with fracing operations if the water table below Hemphill County drops significantly.[424] In the High Plains Underground Water Conservation District No. 1, which is based in Lubbock and covers an area bigger than Massachusetts, new water restrictions are being formulated to begin in 2012, and fracing operations will not be exempted.[425]

Further limiting the coverage of the permitting exception, groundwater withdrawn from a district and transported elsewhere is still subject to all applicable production and export fees.[426] Finally, such exempted wells must still be registered with the water district and well integrity of exempted wells must (1) still be maintained to (1) prevent the leaking of groundwater from an aquifer to a non-aquifer and (2) to prevent groundwater contamination.[427]

General Regulations that Affect Fracing: The only other regulations that apply to fracing operations in Texas also apply to all other oil and gas operations. The RRC promulgates and enforces regulations related to oil and gas matters and has jurisdiction over all "oil and gas wells in Texas; persons owning or operating pipelines in Texas; and persons owning or engaging in drilling or operating oil or gas wells in Texas."[428] Contrary to the practice in other states, the TCEQ is not the primary state regulatory agency with jurisdiction over oil and gas operations, nor the wastes produced during such operations.[429]

Like all oil and gas development in Texas, fracing operations require the RRC to issue a permit authorizing drilling and/or deepening of a well.[430] Besides the standard permitting and the new chemical disclosure requirements, two key areas where the RRC's regulations have an impact on fracing operations are: 16 TEX. ADMIN. CODE § 3.8 "Water Protection" and 16 TEX. ADMIN. CODE § 3.13 "Casing, Cementing, Drilling, and Completion Requirements."

In addition to permitting regulation, § 3.8 also regulates the storage, transfer and disposal of oil and gas wastes. Presumptively, this includes any fracing fluids that are brought back to the surface as part of oil and gas production.[431] Although § 3.46 is specifically intended to regulate injection of fluids as part of enhanced oil recovery or waste injection, the language of § 3.46 could be interpreted to include fracing operations. Specifically, § 3.46 states that a special fluid injection permit is required for "fluid injection operations in reservoirs productive of oil, gas, or geothermal resources." In spite of this language, in actual practice § 3.46 does not currently

423 *Id.*
424 *Id.*
425 Conkwright, *supra* note 49.
426 TEX. WATER CODE ANN. § 36.117(k) (Vernon 2011).
427 TEX. WATER CODE ANN. § 36.117(h)(1-2) (Vernon 2011).
428 TEX NAT. RES. CODE § 81.051 (2011).
429 16 TEX. ADMIN. CODE § 3.30 (2011). This regulation, called the Memorandum of Understanding, sets forth the jurisdictional boundaries between the Texas Commission of Environmental Quality and the RRC.
430 *Id*. § 3.5.
431 *Id*. § 3.8 regulates drilling fluid pits, saltwater and brine storage pits, flare pits, sediment pits, etc. for the storage of oil and gas waste (as defined in § 3.8).

create duties specific to hydraulic fracturing for operators who engage in fracing within the State of Texas.[432] However, if federal regulations are amended to include fracing within the definition of Class II underground injection wells, then the RRC may be forced to follow suit.

Regulation of casing and cementing is the second way in which the RRC's standard oil and gas regulations affect fracing. The key concern of fracing opponents is the potential for fracing fluids to contaminate groundwater. The RRC is confident, however, that the current casing, cementing, drilling and completion regulations in 16 TAC § 3.13 are sufficient to protect the State's groundwater resources from being contaminated by fracing fluids.[433] Therefore, unlike many states, the RRC does not require fluid injection permits for fracing similar to those required by 16 TEX. ADMIN. CODE § 3.46. The RRC holds fast to its claim that state rules for well construction have prevented even a single documented case of groundwater contamination from the injected fluids.[434]

The RRC regulates the use of saline or brackish water drawn from underground reservoirs that are below the base of usable quality water.[435] The RRC requires a permit for wells associated with oil and gas activities that draw such water from formations below the base of usable quality water.[436] Groundwater ownership rights are subject to regulation and control by courts and the Texas legislature.[437] The legislature authorized the creation of Groundwater Conservation Districts ("GCD") to conserve, preserve, protect, recharge and prevent waster of groundwater resources within their boundaries.[438] The drilling and use of an injection water supply well for oil and gas activity or a water well for surface mining activity may by subject to the rules promulgated by the controlling GCD.[439] Water well drillers must submit drilling logs and other required information to the Texas Department of Licensing and Regulation ("TDLR"), and the completion and plugging of water wells must comply with TDLR regulations.[440]

Eagle Ford Task Force: In July of 2011, in response to a multitude of concerns regarding the meteoric rise of development in the Eagle Ford Shale in southwestern Texas (see Figure 1). David Porter, RRC Commissioner, created the Eagle Ford Task Force, whose mission is three-fold: open the lines of communication between all stakeholders, establish best practices for developing the Eagle Ford Shale and promote economic benefits locally and statewide shale region of South Texas to ensure that the Commission can keep up with the development

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432 SMITH & WEAVER, *supra* note 394.

433 Email from Ramona Nye, Media Relations Director, Railroad Commission of Texas, to J. Austin Frost, Associate, Haynes and Boone, LLP (April 13, 2010, 03:36 PM CDT) (on file with author).

434 *Id.* (Quoting Ramona Nye, spokeswoman for the Texas Railroad Commission).

435 *See Water Use in Associations with Oil and Gas Activities Regulated by the Railroad Commission of Texas*, http://www.rrc.state.tx.us/barnettshale/wateruse.php (last visited August 2, 2011).

436 *Id*.

437 *Id*.

438 *Id*.

439 *Id*.

440 *Id*.

boom.[441]

While the RRC is not the agency which governs road use, housing, surface water use and quality/quantity of groundwater, it has taken upon itself the responsibility of bringing together such public interested parties as well as members of industry, other state agencies, local universities, and citizens groups. The task force has thus far met approximately every month in a town affected by Eagle Ford development.[442]

The meetings have highlighted the four largest sources of public and state regulatory concerns encountered thus far in the Eagle Ford region, including water use for fracing, housing shortages caused by the sudden influx of oilfield workers,[443] excessive use of the limited road network in the Eagle Ford play caused by trucks carrying equipment and fracing fluid, and pipeline construction. Pipelines are seen as both a blessing and a burden as they can replace fleets of trucks and thus save roads[444] but which also promote erosion and disrupt land use during their installation, use and repair.

Thus far, the task force has promulgated the following "advisements" regarding pipelines and roads:

(1) Pipeline easements should avoid steep slopes and watercourses where possible;

(2) Pipeline easements should run parallel to road right-of-ways to minimize surface disturbance.

(3) When clearing is necessary for pipeline installation, the width of the 'slash' should be minimized.

(4) Unnecessary damage to trees and other slow-growing vegetation should be avoided.

(5) Because revegetation is a slower process in the arid Eagle Ford region than in places which receive more precipitation, topsoil removed during pipeline installation should be piled near the pipeline easement so it can be used for reclamation as it can significantly accelerate successful revegetation.

(6) After installation of a new line, all rights-of-way should be restored to conditions compatible with existing land use.

(7) Trucking companies should cooperate with the Texas Department of Public

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441 *See* Press Release, RRC, Texas Railroad Commissioner Porter Announces Members of Eagle Ford Task Force, Jul. 27, 2011, *available at* http://www.rrc..tx.us/commissioners/porter/press/072711.php (last visited Aug. 9, 2011).

442 *See* Press Release, RRC, Eagle Ford Task Force Tackles Local Infrastructure Issues, Oct. 12, 2011, *available at* http://www.rrc.state.tx.us/commissioners/porter/press/101211.php (last visited November 1, 2011)(Meetings have thus far been held in Beeville on Aug. 25, Cuero on Sep. 28, and San Antonio, Nov. 2, 2011).

443 In addition to the logistical concerns of housing new workers, concern exists as to the displacement of current low- or fixed-income tenants due to increasing rents.

444 *Id*. (Commissioner Porter has stated that one crude oil pipeline with a diameter of twenty inches can replace approximately 1250 tanker truck trips per day.)

Safety to establish a protocol for companies to receive notice when their drivers receive moving violations or license suspensions.

(8) Trucking companies should avoid peak traffic hours, school bus hours and community events.

(9) Trucking companies should observe overnight quiet periods

(10) Drilling operators and trucking companies should ensure adequate parking and delivery areas located off of through road to avoid lane/road blockage.

While these 'advisements' do not come freighted with any regulatory authority, they will be presented to various state agencies for consideration for future rulemaking.

Utah

As of August 25, 2011, no laws or regulations specifically address fracing in Utah.[445]

West Virginia

The West Virginia Office of Oil and Gas (the "*OOG*") within the state's Department of Environmental Protection (the "*DEP*") is "responsible for monitoring and regulating all actions related to the exploration, drilling, storage and production of oil and natural gas," including ensuring that surface and groundwater is protected from drilling activities.[446] To that end, the OOG is the permitting authority for the state in all matters respecting the exploration, development, production, storage, and recovery of oil and gas.[447] A permit is required before any person can commence any "well work."[448] "Well work" is defined as including the stimulating or pressuring by injection of any fluid into a well.[449] To "stimulate" a well is "to increase the inherent productivity of an oil or gas well" by, among other actions, fracing the well.[450]

Specifically with respect to hydraulic fracturing, West Virginia runs its own Underground Injection Control (UIC) Program, which regulates underground injections by five classes of wells.[451] "Class II" wells include wells "injecting fluids for enhanced recovery of oil or natural gas."[452] Class II wells must either be authorized by rule (in limited instances), or by permit.[453]

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445 Bogle, *supra* note 253 (reporting confirmation by Phil Lear, practitioner in Utah, of no regulation.)

446 Office of Oil and Gas, W. VA. DEP'T OF ENVTL. PROT., http://www.dep.wv.gov/oil-and-gas/Pages/default.aspx (last visited July. 1, 2011).

447 W. VA. CODE § 22-6-2(c)(12) (2009).

448 W. VA. CODE § 22-6-6(a) (2009).

449 W. VA. CODE § 22-6-1(v) (2009).

450 W. VA. CODE § 22-6-1(s) (2009).

451 W. VA. CODE R. § 47-13-1.1 (2002).

452 W. VA. CODE R. § 47-13-4.2.b (2002).

453 W. VA. CODE R. § 47-13-9.1 (2002); *see also* W. VA. CODE title 22, art. 6 (2009) (governing criteria and standards for Class II wells).

Applications for a permit to stimulate a well must be accompanied by a bond,[454] a plat,[455] and a corrective action plan "to prevent movement of fluid into underground sources of drinking water."[456] The applicant must also demonstrate the mechanical integrity of the well,[457] comply with notice requirements,[458] and pay a $150.00 reclamation fee for each activity for which an application is required.[459] After a public comment period and hearing,[460] the Director of the DEP will conduct a review of the application, including inspections if necessary.[461] Permits may be denied if the DEP Director determines that the applicant has previously committed a substantial violation of a previously issued permit, or if the proposed well work will constitute a hazard to human safety or to freshwater sources.[462]

Once a permit has been issued and the well completed, the operator of the well must file a log that includes descriptions of the character, depth, and thickness of geologic formations encountered, (including freshwater*)*.[463] Moreover, the operator is required to retain all records "concerning the nature and composition of injected fluids until three (3) years after completion of any plugging and abandonment" of the Class II well.[464] Permits are effective for a fixed term not to exceed five years.[465]

Willful violations of any rule or order promulgated by the OOG are subject to a civil penalty—recoverable by the state through the filing of a civil lawsuit—of up to $2500.00 per day after notice of the violation is given by the DEP.[466] Willful violations of any provisions respecting drilling and casing of the well are deemed criminal misdemeanors and subject the offender to penalties of fines up to $5000.00, imprisonment for up to one year, or both.[467] Additionally, the DEP Director is authorized to bring suit for injunctive relief to enjoin any violations or threatened violations.[468] Finally, if an inspector of the OOG finds that, along with a violation or threatened violation, imminent danger to humans or freshwater sources exists from well operations, that inspector is authorized to issue an order requiring the well operator to

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454 W. VA. CODE §§ 22-6-6(b), -12(c), -26 (2009). The bond required of an applicant is the same bond required of all well operators and is conditioned on full compliance with all laws and rules related to, among others, the drilling, stimulating, and plugging and abandonment of the well. W. VA. CODE § 22-6-26(b) (2009).

455 W. VA. CODE § 22-6-12(a) (2009).

456 W. VA. CODE R. § 47-13-13.9.a (2002).

457 W. VA. CODE R. §§ 47-13-6.2, -13.7.h (2002).

458 W. VA. CODE §§ 22-6-6(c)(11), -9, -13 (2009).

459 W. VA. CODE § 22-6-29(b) (2009).

460 W. VA. CODE § 22-6-10 (2009); W. VA. CODE R. §§ 47-13-13.24.b, -13.27 (2002).

461 W. VA. CODE § 22-6-11(2009).

462 W. VA. CODE §§ 22-6-6(h), -11 (2009).

463 W. VA. CODE § 22-6-22 (2009). Section 22-6-22 was amended by the West Virginia legislature on March 8, 2010. The amendments include making filing requirements applicable only to "shallow wells" or "deep wells" drilled, and increase the types of information required to be included in the "completion report." S.B. 382, 2010 Leg., Reg. Sess. (W. Va. 2010), *available at* http://www.legis.state.wv.us/Bill_Text_HTML/2010_SESSIONS/RS/BILLS/sb382%20enr.htm (last visited July 5, 2011).

464 W. VA. CODE R. § 47-13-13.6.b (2002).

465 W. VA. CODE R. § 47-13-13.13 (2002).

466 W. VA. CODE § 22-6-34(a) (2009).

467 W. VA. CODE § 22-6-34(b) (2009).

468 W. VA. CODE § 22-6-39 (2009).

immediately cease all well operations until the danger has been abated.[469]

Operators of Class II wells in West Virginia are required to permanently dispose of the waste water generated through the fracing process.[470] Operators will often temporarily store the fracing fluid in pits, although at least one operator unwittingly created environmental problems for the Monongahela River by sending its fracing fluid for treatment and disposal at a sewage treatment plant that was too small to handle the volume of effluent.[471] According to the OOG, while "a good bit of [fracing] water [is] reused," in volumetric terms most of the fracing fluid is ultimately disposed by reinjecting it underground through a UIC permit.[472]

The DEP—through the OOG and the Division of Water and Waste Management—has released a guidance document and permit addendum "designed to better manage water use and disposal [of fracing fluids] by the oil and gas industry when drilling in the Marcellus Shale formation." The guidance document and addendum can be found on the DEP's website at www.dep.wv.gov/oil-and-gas.[473]

On March 5, 2010, the DEP also released a "hydrofracturing reporting form." Applicable to wells that use over 750,000 gallons of water in the fracing process, the form requires information on: (1) the amount and location from which water was withdrawn; (2) the amount injected into the well; (3) the well's location; (4) the amount of flow-back water recovered;[474] and (5) the method and location of disposal, treatment, or recycling of the flow-back water. The form must be submitted within thirty days of the flow-back period.[475]

At the legislative level, West Virginia recently adopted the "Oil and Gas Wells and Other Wells" rule requiring, with some exceptions based on results of soil analyses, protective liners in all pits and impoundments used for holding fracing wastewater.[476] In 2011, legislation that would expand the rule, the "Hydraulic Fracturing and Horizontal Drilling Gas Act" (House Bill 2878 and Senate Bill 258), was also introduced. If passed, the act would require that all impoundments and drilling pits be constructed with an impermeable synthetic liner.[477] The

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469 W. VA. CODE § 22-6-3(a) (2009).

470 Ken Ward Jr., *DEP Rules on Hydraulic Fracturing Called Baby Steps*, CHARLESTON GAZETTE, July 16, 2009, at P1C.

471 *Id*.

472 Pam Kasey, *Pa., W. Va. Address Salt Problems Differently*, THE ST. J. (Morgantown), Jan. 8, 2010, at 21.

473 George Hohmann, *State Issues Guide for Natural Gas Drillers*, CHARLESTON GAZETTE, Jan., 14, 2010, at P2A.

474 "Flow-back water" being fracing fluids returning to the surface after injection and fracing.

475 West Virginia State Agency Directory, News, Oil and Gas Companies Must Register Marcellus Shale Hydraulic Fracturing Water Use, *available at* http://www.dep.wv.gov/news/Pages/OilandgascompaniesmustregisterMarcellusShalefracwateruse.aspx (last visited July 5, 2011).

476 W. VA. C.S.R. § 35-4-16.4(d) (2010).

477 *See* DONALD S. GARVIN, JR, COMPARISON OF DEP AND JUDICIARY A DRAFT OIL AND GAS BILLS (2011) *available at* http://www.uppermon.org/Mon_Watershed_Group/Comparison%20of%20Draft%20Bills%20(revised%20Jan%2026).pdf (providing a comparison of two comprehensive proposals regulating Marcellus Shale development).

Senate bill has not come out of the Committee on Judiciary, while the House bill came out of the Committee on Judiciary and was read for the second time on March 1, 2011.

While the recent legislative session produced several proposed bills to increase the regulation of fracturing in the Marcellus formation, only Senate Bill 424 passed its house of origin.[478] Ultimately, even that bill died after the House of Delegates failed to vote on it before the end of the regular session.[479] The bill contained several provisions specific to horizontal drilling, including: the requirement of a water management plan for any horizontal well that involves the withdrawal of more than 210,000 gallons of water in a given month of fracturing; mandatory recordkeeping and reporting for well operators regarding water use and handling; and a certificate of approval for the construction of large freshwater or flow-back impoundments.[480]

Additionally, the 2011 session ended without setting new limits on the amount of total dissolved solids (TDS) in streams. On March 8, 2011, the House Judiciary Committee rejected an amendment to Senate Bill 121 that would set an in-stream water quality standard of no more than 500 milligrams per liter for salt from produced water in surface waters. The TDS standard, which was first unsuccessfully proposed in a 2009 bill, is aimed at protecting aquatic life after 22,000 fish and all of the mussels in Dunkard Creek in Monongalia County near Morgantown were killed. The cause of death was an algae bloom whose growth was alleged to be stimulated by high-salinity fracing fluid run-off from a point source upstream.

At the local level, on June 21, 2011, the city of Morgantown issued an ordinance to limit Marcellus Shale drilling and hydraulic fracturing to within one mile of the city's corporate limits.[481] The ordinance was passed after residents discovered that Northeast Natural Energy had been permitted to drill two natural gas wells near Morgantown's water treatment plant. The city of Westover is also considering an ordinance to completely ban drilling in some areas, while allowing drilling in other areas if a company can prove that its operations are safe.[482] It remains to be seen whether these local efforts to regulate fracing will withstand legal challenges.[483]

Wyoming

Oil and gas drilling and production in Wyoming are regulated by the Wyoming Oil and Gas Conservation Commission (the "*WOGCC*") pursuant to authority granted by Title 30,

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478 S.B. 682, 80th Leg., 1st Sess.

479 Phil Kabler & Alison Knezevich, *Bill to Regulate Marcellus Shale Drilling Dies*, CHARLESTON GAZETTE, March 12, 2011, at P1A.

480 S.B. 422, 80th Leg., 1st Sess.

481 Duane Nichols, *Morgantown City Council Passes Ban on Horizontal Drilling With Fracking*, FrackCheckWV (June 22, 2011), http://www.frackcheckwv.net/2011/06/22/morgantown-city-council-passes-ban-on-horizontal-drilling-with-fracking/.

482 Sharon O. Flanery, *Zoning Ordinances, the Marcellus Opportunity, and Regional Developments*, STEPTOE & JOHNSON, *available at* http://www.steptoe-johnson.com/news/news/Zoning-Ordinances-the-Marcellus-Opportunity-and-Regional-Developments,1102.aspx.

483 Vicki Smith, *Morgantown's New Mayor Worries about Validity of Part of City's New Gas Drilling Ordinance*, ASSOCIATED PRESS, July 08, 2011, *available at* http://washingtonexaminer.com/news/2011/07/new-wva-mayor-worried-about-drilling-ordinance?

Chapter 5 of the Wyoming Statutes.[484] The WOGCC's mission is to promote the beneficial and environmentally responsible development of Wyoming's oil and gas resources, and its regulations are intended to protect human health and the environment "through the utilization of proven methods which are designed to avoid contamination of the soil, groundwater, and surface water at a drilling or producing location."[485]

Before any drilling or hydraulic fracturing work can begin in Wyoming, the operator must submit to the WOGCC's Supervisor (the "Supervisor"), and the Supervisor must approve, an Application for Permit to Drill or Deepen (Form 1). In addition, the application should be accompanied by an accurate plat showing the location of the proposed well.[486] Some of the information to be included in the application and its addendums are:

- proposed total depth/endpoint to which the well will be drilled,
- estimated depth to the top of important biostratigraphic markers and objective horizons,
- the proposed casing program, including size and width thereof,
- the depth at which each casing string is to be set and the amount of cement to be used,
- formation depth, geological and hydrological detail of useable groundwater underlying the drilling and spacing unit.[487]

To change plans previously approved on the application (Form 1), a Sundry Notice (Form 4) should be filed with the Supervisor. Like the application, the notice must be approved by the Supervisor before work begins and should list:

- the depth of perforations or the openhole interval,
- the source of water and/or trade name of fluids,
- the type of proppants, and
- the estimated pump pressures. [488]

The Application for Permit to Drill of Deepen must also be accompanied by a statement of compliance certifying that the oil and gas operator has (i) provided notice of the proposed oil and gas operations to the surface owner; (ii) engaged in good faith negotiations to reach a surface

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484 WYO. STAT. ANN. §§ 30-5-101 – 30-5-126 (2009).
485 Wyo. Oil & Gas Conservation Comm'n ("*WOGCC*") Rules & Regulations, Ch. 2, § 1(b) (2010).
486 WOGCC Rules & Regulations, Ch. 3, § 8(c) (2010).
487 WOGCC Rules & Regulations, Ch. 3, §§ 1(a), 8(a) and 8(c) (2010).
488 WOGCC Rules & Regulations, Ch. 3, § 1(a) (2010).

use agreement with the surface owner, and (iii) satisfied the conditions of WYO. STAT. ANN § 30-5-402(c).[489]

In addition, the applicant must comply with casing and cementing requirements promulgated by the WOGCC to ensure surface water isolation, reservoir isolation, and cased hole integrity for hydraulic fracturing.[490] Production and intermediate casing design provide reservoir isolation; and casing must be cemented from bottom to top to ensure that there are no voids.[491]

Finally, after the hydraulic fracture treatment is complete, the Supervisor must be provided with a "detailed account" of:

- the work done and the manner in which such work was performed;
- the daily production of oil, gas and water both prior to and after the operation;
- the size and depth of perforations;
- the quantity of sand, crude, chemical, or other materials employed in the operation; and
- any other pertinent information of operations which affect the original status of the well.[492]

Current Developments in Permitting Requirements for Fracing Operations: On August 16, 2010, in an apparent response to complaints from two Wyoming communities of contaminated water supplies, the WOGCC considered stricter reporting rules for fracing, including additional requirements that (i) operators disclose "proprietary chemical component detail" of the fluids used in the fracturing process;[493] (ii) wells undergoing hydraulic fracturing be cased in a way that prevents groundwater contamination; and (iii) operators be aware of all permitted water wells within a quarter-mile of a well undergoing fracing.[494]

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489 WOGCC Rules & Regulations, Ch. 3, § 8(d) (2010). Section 30-5-402 is entitled "Entry upon land for oil and gas operations and nonsurface disturbing activities; notice; process; surety bond or other guaranty; negotiations."

490 WOGCC Rules & Regulations, Ch. 3, § 22 (2010).

491 *Id.*

492 WOGCC Rules and Regulations, Ch. 3, § 12 (2010).

493 According to Tom Doll, the WOGCC's Supervisor, "Now we're going to ask them to provide how much of that is a gelling agent, how much of that is a surfactant, how much of that is a biocide, and what is the biocide name and what is the concentration." Addie Goss, *Vote May Come on New Fracing Rules*, WYOMING PUBLIC RADIO NEWS, April 2, 2010.

494 *See* Staff, *State Oil and Gas Commission Getting Input on Proposed Rule Changes,* WYOMING ENERGY NEWS, March 29, 2010; *see also* Bob Moen, *Wyoming Community Blames Fracing for Water Problems*, THE BILLINGS GAZETTE, September 7, 2009 (reporting that the EPA has launched an investigation into the complaints of Pavilion, WY residents after it was determined that 11 of 39 wells in the area were contaminated).

After the WOGCC held public hearings on the proposed rule changes, Wyoming became the first state in the country to promulgate rules mandating the disclosure of chemicals in fluids used for fracing.[495] Under the regulations, which went into effect on September 15, 2010, operators must submit to the WOGCC a notice of intent to conduct fracing operations along with a complete list of chemicals used in fracing operations on a well-by-well basis.[496] Operators are also required to provide the CAS number, compound type, and compound concentrations or rates proposed to be mixed and injected as part of the hydraulic fracturing process.[497] The location of permitted water supply wells within ¼ mile of the fracing operations must also be reported, along with a summary of the geology and aquifers encountered uphole from the casing point and the operator's plan to maintain well integrity to avoid contamination. Plans for casing and cementing, along with driller's log information and reports of pressure failures are now required by the WOGCC.

Finally, once the job is complete, a report of the concentration of each chemical must be submitted.[498] This includes the actual names of the ingredients and their CAS numbers. However, operators do retain the right to claim that certain chemical specifications of the fracing fluid are proprietary and should be kept confidential by WOGCC.[499]

For almost a year after promulgation of these rules, it remained unclear as to what extent industry will make claims of proprietary for certain fracing fluid ingredient.[500] Then, on August 24, 2011, the WOGCC agreed to keep secret the identities of 146 chemicals used by seven companies in their fracing operations since the disclosure rules went into effect.[501] No company has requested blanket exemptions for all chemicals.

Wyoming Rules and Statutes Governing Byproduct Water Use and Storage: Jurisdiction over water use and rights is vested with the Wyoming State Engineer.[502] The office of the State Engineer directs water use and also enforces regulations related to water by-products, defined as:

"[W]ater which has not been put to prior beneficial use, and which is a by-product of some nonwater-related economic activity and has been developed only as a result of such activity. By-product water includes, but is not limited to, water resulting from the operation of oil

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495 Brodie Farquhar, *Wyoming First in Nation to Require Public Disclosure of Chemicals Used in Gas, Oil Drilling*, NEW WEST (Sept. 08, 2010), *available at* http://www.newwest.net/topic/article/wyoming_first_in_nation_to_require_public_disclosure_of_chemicals_used_in_g/C618/L618/.

496 WOGCC Rules and Regulations, Ch. 3, § 45 (d) (2010).

497 *Id*.

498 WOGCC Rules and Regulations, Ch. 3, § 45 (h) (2010).

499 WOGCC Rules and Regulations, Ch. 3, § 45 (f) (2010).

500 *See generally*, Hannah Wiseman, *Trade Secrets, Disclosure, and Dissent in Fracturing Energy Revolution*, 111 COLUM L. REV. SIDEBAR 1 (2011) (arguing that the right of companies to claim trade secret status should be eliminated).

501 Jeremy Fugleberg, *Wyoming Regulators Exempt 146 'Fracing' Chemicals from Public Disclosure*, BILLINGS GAZETTE, Aug. 24, 2011, *available at* http://billingsgazette.com/news/state-and-regional/wyoming/article_4a291cb8-28d0-5468-8c92-8beb49615c95.html#ixzz1YzM6cD4e (last visited Sep. 25, 2011).

502 WYO. STAT. ANN. §§ 41-3-905 and 41-3-909 (2009).

well separator systems or mining activities such as dewatering of mines."[503]

Any person intending to appropriate/use by-product water, including water from fracing operations, for beneficial use must file an application with the State Engineer on the forms and in the manner prescribed for groundwater applications.[504] 'By-product water' is considered as being in the same class as groundwater for the purposes of administration and control.[505]

Storage of by-product water is also regulated by the State Engineer. If a surface impoundment will be used to store produced water for additional beneficial uses, a reservoir permit must be obtained from the State Engineer prior to commencement of construction of the impoundment.[506] In addition to submitting a Form 14A application for a "Produced Water Pit," the applicant must provide a standard water analysis (Form 17), to include "maximum and average estimated inflow, size of pit, freeboard capacity, origin of pit contents, method of disposal of pit contents, maximum fluid level above average ground level, distance to closest surface water, depth to groundwater, subsoil type and type of sealing material."[507] If applicable, a plan view map and topographic map, of "sufficient size and detail to determine surface drainage system and all natural waterways and irrigation systems", must be attached as well.[508] The WOGCC has also implemented rules and regulations governing the location, marking and construction of these produced water pits.[509]

Fracing in Indian Country

Indian Country consists of a patchwork of land owned and controlled by a variety of authorities.[510] In addition to the actual communally-owned reservation lands, there are plots owned by individual Indians, both in trust with the federal government, and by themselves in fee.

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503 WYO. STAT. ANN. § 41-3-903 (2009).

504 WYO. STAT. ANN. § 41-3-904 (a) (2009).

505 *Id*.

506 WYO. STAT. ANN. § 41-3-301 (2009).

507 WOGCC Rules & Regulations, Ch. 4, § 1(r) ("Because of the potential for direct communication with shallow groundwater resources of the state, application for approval of construction of percolation pits for containment and discharge of water produced in association with coalbed methane gas in the Power River Basin may be accompanied by a review of the groundwater issues by the Dept. of Environmental Quality as determined by the Supervisor. If the proposed construction meets with requirements of the Commission's rules, the application may be granted.").

508 *Id.*

509 WOGCC Rules & Regulations, Ch. 4, §§ 1(t) - (w) (2010).

510 18 U.S.C. § 1151 (2006) is a law within the federal criminal code, but its definition of "Indian Country" has received credence in civil cases such as *Alaska v. Native Village of Venetie Tribal Government*, 522 U.S. 520 (1998) and *Mustang Production Co. v. Harrison*, 94 F.3d 1382 (10th Cir. 1996) *cert. denied*, 520 U.S. 1139 (1997). As defined in the code, "Indian Country" is:

> "(a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the border of the United States whether within the original or subsequently acquired territory thereof, and whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same."

Non-Indians also own land within the reservation boundaries and the question of who governs these owners provides the greatest source of consternation regarding state, tribal, and federal regulation of exploration and development.

Most tribes in the United States look to the Bureau of Indian Affairs ("*BIA*") to provide regulation of oil and gas development on their reservation lands.[511] To protect tribes from fraud, oil and gas development was historically the exclusive realm of the BIA. However, as some tribes became more sophisticated with regards to mineral development, they agitated for more control. Now, tribes may assert regulatory control over non-natives on reservation lands whether the specific land in question is considered tribal or is held in fee by non-Indians.[512] State regulation, particularly if a strong state interest is not implicated, is considered to be pre-empted by tribal and federal authority.[513] This is especially the case if state regulatory control would disrupt a pre-existing tribal regulatory scheme.[514]

The general rule is that a tribe's inherent government authority does not allow the regulation of non-native activity on non-native land within "Indian country."[515] This rule is subject to two major exceptions. The first is that non-natives can enter into consensual dealings with tribes, thus subjecting themselves to tribal regulation and liability.[516] The second is that tribes can regulate non-native behavior in Indian country where the non-native behavior, such as the operations of a developer, significantly affects the health and welfare of a tribe.[517]

Development of the mineral estate sometimes entails both exceptions. The first is often seen in modern oil and gas leases executed by tribes operating under the auspices of the 1982 Indian Mineral Development Act (IMDA),[518] which allows tribes to negotiate and lease more-or-less directly with developers, subject to the ultimate approval of the Secretary of the Interior. The second exception would be invoked, at least in theory, when development activities lead to surface damage or groundwater contamination that adversely affects a tribe.[519]

The SDWA and the Clean Water Act (CWA)[520] were amended to give tribes the same standing as states to assume responsibility for water quality control in Indian country.[521] The scope of tribal control granted reflected the complex landholding situation on many reservations, allowing the tribe to regulate reservation, trust lands, allotted lands, and fee lands of both Indians

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511 *See* 25 C.F.R. § 225.1 (2009) (outlining the purpose and scope of the BIA).

512 Judith V. Royster and Rory SnowArrow Fausett, *Control of the Reservation Environment: Tribal Primacy, Federal Delegation, and the Limits of State Intrusion*, 64 WASH. L. REV. 581, 597 (1989).

513 *New Mexico v. Mescalero Apache Tribe*, 462 U.S. 324, 344 (1983) (holding that native control over regulation of non-native fishing and hunting on tribal land was exclusive).

514 *Id.* at 338.

515 *Montana v. United States*, 450 U.S. 544, 565 (1981).

516 *Id*.

517 *Id.* at 566.

518 25 U.S.C. §§ 2101-2108 (2006).

519 The second *Montana* exception has proved to be an elusive protection for tribes to invoke.

520 33 U.S.C. § 1251 *et seq* (2006).

521 Clean Water Act Amendments, 33 U.S.C. § 1377 (2006).

and non-Indians.[522]

Furthermore, a tribe can gain recognition as an entity, which would enable it to invoke and enforce environmental regulations. The tribes-as-states (TAS) provisions in the SDWA and CWA require tribes to meet three criteria to be treated the same as states—i.e. have the authority to implement programs allowed by the two acts.[523] First, the tribe must be federally recognized.[524] Second—and depending on the act invoked—the tribe must either show (1) that the power to be exercised must be limited to lands held in fee by the tribe, held in trust by the federal government, held in fee by a tribal member, or are otherwise in Indian country or (2) that the tribe exercises jurisdiction over the land in question.[525] Finally, the tribe must show that it is capable of carrying out the necessary duties and investigations to enforce regulations, such as providing adequate and qualified oversight personnel and drafting workable regulations.[526]

Currently, no Indian tribes have tribal statutes or regulations which touch directly upon fracing. Developers leasing from tribes should be become familiar with the production and environmental regulations of the appropriate tribe(s) or the current BIA regulations which will govern their operations.

Fracing in Canada

Currently Canada has no national laws or regulations relating to the development of shale gas resources. Fracturing has generally been regulated at the province-level in Canada, but this soon may change. In a June 2011 speech before the House of Commons, Environment Minister Peter Kent said that the federal government could exercise its authority to "prevent the release of a toxic substance from a shale gas site."[527]

This regulation would be handled by Environment Canada – the Canadian equivalent of the United States Environmental Protection Agency – based on powers granted to Environment Canada under the Canadian Environmental Protection Act.[528] Under the Act, Environment Canada is responsible for taking action to protect air, water, and wildlife.[529] Regulations promulgated under the Canadian Environmental Protection Act currently require oil and gas producers to maintain records of chemical used at drill sites.[530] This may expand into requirements that producers not only maintain records, but also disclose information to

522 *See id.* § 1377(e)(2) (stating that an Indian tribe may manage and protect water resources which are held by an Indian tribe, the United States in trust for Indians, a member of an Indian tribe if such property interest is subject to a trust restriction or alienation, or otherwise within the borders of an Indian reservation).

523 Safe Drinking Water Act (SDWA) tribes-as-state provisions: 42 U.S.C. § 300j-11(a); Clean Water Act (CWA) tribes-as-states provisions: 38 U.S.C. § 1377(e).

524 SDWA: 42 U.S.C. § 300j-11(b)(1); CWA: 38 U.S.C. § 1377(e)(1).

525 SDWA: 42 U.S.C. § 300j-11(b)(2); CWA: 38 U.S.C. § 1377(e)(2).

526 SDWA: 42 U.S.C. § 300j-11(b)(3); CWA: 38 U.S.C. § 1377(e)(3).

527 Magill, Jim, *Canadian Government Poised to Take Role in Fracking Rules*, PLATTS (June 17, 2011), *available at* http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/6199302 (last visited July 29, 2011).

528 *Id*.

529 *See generally* Canadian Environmental Protection Act (1999), c. 33.

530 *See* Magill.

Environment Canada, or even the general public, about the chemicals used in hydraulic fracturing.[531]

The dearth of national Canadian laws and regulations relating to hydraulic fracturing is due to the fact that practice of exploiting shale plays is in its infancy in Canada, relative to the dominance of that practice in the United States.[532] There has been more government reaction to fracturing at the province-level; however, British Columbia is the only Canadian province that has seen significant shale gas development.[533] This general lack of fracturing activity has not stopped other provinces from speaking up about fracturing.

In March 2011, the province of Quebec imposed a moratorium on all hydraulic fracturing activity.[534] The moratorium will be in place until an independent study assessing the environmental impact of fracturing by a panel of eleven experts is complete.[535] This study is expected to take two to three years.[536] It should come as no surprise that Quebec, even with its relatively low hydraulic fracturing activity, put fracturing on hold – the people of Quebec support fracturing less than any other Canadian province.[537] In a poll by polling firm Angus Reid, only 22% of Quebec is in favor of fracturing.[538] The national average is 31% and in Alberta, the province that fracturing enjoys the highest level of support, 46% of the people are in favor.[539]

While a common province-level response is to impose a moratorium on hydraulic fracturing, Alberta has taken a more regulatory approach. As early as 2006, the Energy Resources Conversation Board of Alberta (ERCB) began promulgating directives covering fracturing operations.[540] In 2009, the ERCB revised the regulations in response to the "recent trend in Alberta to develop shallow gas reservoirs . . . using high fracture volumes, pump rates, and pressures."[541] The 2009 rules were created by a "Multi-stakeholder Shallow Fracturing Steering Committee."[542]

The 2009 rules primarily focus on fracturing near a water well. The rules require that if a gas well that will utilize hydraulic fracturing is located within 200 meters of water well, the

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531 *Id*.

532 *Id*.

533 *Id*.

534 Van Praet, Nicolas, *Quebec Moratorium Leaves Shale Gas Drillers Staggering*, FINANCIAL POST (June 30, 2011), *available at* http://www.canada.com/technology/Quebec+moratorium+leaves+shale+drillers+staggering/5031205/story.html (last visited July 29, 2011).

535 *Id*.

536 *Id*.

537 *Id*.

538 *Id*.

539 *Id*.

540 *See* ERCB Directive 027: Shallow Fracturing Operations—Restricted Operations (August 14, 2009), available at http://www.ercb.ca/docs/documents/directives/Directive027.pdf (last visited July 29, 2011) (hereinafter "*ERCB Directive*").

541 *Id*.

542 *Id*.

fracturing must occur below a specified depth.[543] The "specified depth" is equal to the depth of the water well, plus fifty meters.[544] According to the rules, the "fifty meters" reflects the "use of a consistent conservative safety margin."[545] Additionally, the producer must notify any landowners who own active water wells within 200 meters of the proposed fracturing activities.[546]

In addition to the requirements related to water wells, no fracturing treatment can occur within fifty meters of the vertical depth of the bedrock surface.[547] The "bedrock surface" is defined as the "consolidated rock underlying the unconsolidated glacial or drift material."[548] Producers can use various methods for determining the depth of the bedrock surface, including water drilling reports and bedrock topography maps.[549] This new rule could play a role in determining where a well should be located. In some areas, the bedrock surface is not very deep. In other areas, buried glacial channels and valleys may be greater than 200 meters deep, resulting in the bedrock surface being significantly deeper than in areas without such glacial channels and valleys.[550] The rule is not flexible – fracturing must still occur more than 50 meters from the bedrock surface, even if the bedrock surface is already quite deep in the ground.

The 2009 rules also require that fracture treatments use "only non-toxic fracture fluids above the base of groundwater protection."[551] The ERCB is allowed to request information on the composition of fracture fluids.[552]

Federal Regulation of Fracing

Bureau of Land Management

The Bureau of Land Management ("*BLM*") has considered fracing fluid disclosure regulation for development on public lands under its stewardship. The agency has hosted three public meetings in Arkansas, Colorado and North Dakota during 2011.[553] While expressing that industry already does a "pretty darn good job" maintaining well integrity and promoting the use of best practices on public lands and that the BLM has no evidence that fracing has "adversely affected groundwater,"[554] BLM director Robert Abbey has said that the BLM has decided to wait for the final results of studies by the Department of Energy before deciding on whether to

543 *Id*.
544 *Id*.
545 *Id*.
546 *See* ERCB Directive 027, *supra* note 540.
547 *Id*.
548 *Id*.
549 *Id*.
550 *Id*.
551 *Id*.
552 *See* ERCB Directive 027, *supra* note 540.
553 Phil Taylor, *BLM Chief Says Fracing is Safe but Wants Disclosure, Blowout Regs*, E&E REPORTER, Mar. 8, 2011.
554 *Id*.

promulgate rules regulating fracing operations.[555]

Environmental Protection Agency

The first half of the 1970s brought with it a host of federal environmental regulation starting with the Clean Air Act Amendments of 1970.[556] Subsequently, the Safe Drinking Water Act, passed in 1974 after a two year review, provided for the regulation of groundwater through the prism of "cooperative federalism." Before the 1970s, federal regulation was typically entirely promulgated by Congress with little state input and then enforced by federal agencies created specifically for that purpose. "Cooperative federalism" is the concept of sharing oversight and enforcement responsibility between federal and state entities.

The federal regulation of hydraulic fracturing, primarily under the SDWA,[557] has been the subject of much debate.[558] Included within the SDWA is a program that provides for regulatory management of the injection of fluids whose injection may result in contamination of underground sources of drinking water.[559] This program is known as the Underground Injection control ("*UIC*") program. Under the SDWA, states can retain primacy over their own UIC own program of groundwater protection if they submit their proposed UIC program to the EPA for approval and unless the EPA determines that the state's UIC program does not meet the SDWA's standards. If approved, the state retains primacy, administers the program, and has responsibility for regulation and enforcement.

Under the SDWA and the EPA's associated rules, for a state program to be approved, states must prohibit underground injection unless it is authorized.[560] 'Underground injection' is defined as the "subsurface emplacement of fluids by well injection."[561] In 2005, legislative amendments made clear that the SDWA does not regulate hydraulic fracturing operations.[562] The Energy Policy Act of 2005 amended the SDWA to exclude from the definition of underground injection "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations relating to oil, gas, or geothermal activities."[563] Many sources critical of the exception refer to it as the "Halliburton Loophole."[564] Thus, with the exception of fracing using diesel fluids, the SDWA does not impose direct regulation.

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555 Jim Snyder and Katarzyna Klimasinska, *Natural-Gas Fracking Rules Considered by U.S. for Federal Lands*, BLOOMBERG, Aug. 18, 2011.

556 Clean Air Act Amendments of 1970, Pub.L. No. 91-604, 84 Stat. 1676.

557 42 U.S.C. 8300rf *et seq*.

558 *Compare* New York Times Editorial, *Finding Natural Gas, Safely*, N.Y. TIMES, Mar. 20, 2010, at A20 (in favor application of the SDWA to fracing), *with* Christopher S. Kulander, *Feds Haven't Made Case for Oversight of Fracking*, HOUSTON CHRONICLE, Apr. 22, 2010, at B11, *and* Wes Deweese, *Fracturing Misconceptions: A History of Effective State Regulation, Groundwater Protection, and the Ill-Conceived FRAC Act*, 6 OKLA. J.L. & TECH. 49 (2010) (against application of the SDWA to fracing)

559 42 U.S.C. 8300h.

560 *See* 40 C.F.R. 145.11(a)(5).

561 42 U.S.C. § 300h(d)(1).

562 *Id*.

563 Aug. 8, 2005, Pub.L. 109-58, Title III, § 322, 119 State. 694).

564 "The Halliburton Loophole" New York Times (Nov. 9, 2009), *available at* www.nytimes.com/2009/11/03/opinion/03Tue3.html (last visited May 4, 2010).

In the last year, the use of diesel fuels in fracing fluids has come under increasing scrutiny. Notwithstanding the language of the Energy Policy Act, the EPA thereafter failed to regulate the use of diesel in fracing operations. In January of 2011, United States Representatives Henry Waxman, Edward Markey and Diana DeGette sent a letter to EPA Administrator Lisa Jackson reporting that diesel had been used in fracing operations without requiring any permits and urged Administrator Jackson to examine and regulate the use of diesel fuel in fracing operations(hereinafter, the "Waxman Letter").[565]

The EPA has begun affirmative steps to provide explicit permitting processes to oil and gas producers who use diesel in their fracing operations. In the summer of 2010, EPA apparently modified its website on hydraulic fracturing to explicitly state that "any service company that performs hydraulic fracturing using diesel fuel must receive prior authorization from the UIC program."[566] More recently, According to the EPA's website, it is developing Underground Injection Control Class II permitting procedures for using diesel fuels in fracing fluids. In May and June of 2011, EPA held a number of stakeholder meetings with state and tribal leaders, federal representatives, industry representative and special-interest environmental groups to accept comments on its development of guidance on permitting fracturing activities using diesel fuels.[567] EPA indicates that its schedule is to issue draft guidance for permitting of hydraulic fracturing using diesel in the summer of 2011, with a public comment period on the draft guidance in the fall of 2011. Key issues that EPA is considering include what should be considered diesel fuels, what important siting considerations are and what should the permit duration be, given the nature of hydraulic fracturing.[568]

In the past legislative session, legislation was introduced to bring *all* aspects hydraulic fracturing under federal oversight. Bills were filed in both the U.S. House and Senate to reverse the changes to the SDWA made in the Energy Policy Act of 2005 and bring hydraulic fracturing operations within the definition of underground injection.[569] The proposed legislation also would have required the disclosure of the chemical constituents of the fracturing fluid and proppants, which then would be posted on a government-approved website. However, the legislation did not pass.

Further scrutiny of fracing will undoubtedly occur as the EPA moves forward on a study

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565 Letter from Representatives Henry Waxman, Edward Markey and Diana DeGette to the Honorable Lisa Jackson, Administrator of the U.S. Environmental Protection Agency (January 31, 2011), *available* at http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f (last visited July 29, 2011).

566 *See* EPA, *Regulation of Hydraulic Fracturing by the Office of Water*, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm (last visited August 2, 2011).

567 *See* EPA, *Underground Injection Control Guidance for permitting Oil and Natural Gas Hydraulic Fracturing Activities Using Diesel Fuels, available at* http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroout.cfm#diesel (last visited July 29, 2011).

568 *See* EPA, *Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels*, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HF-With-Diesel-Guidance-Webinar-May-2011-revised-508.pdf (last visited August 2, 2011).

569 *See* Senate Bill S. 1215, House Resolution H.R. 2766.

of hydraulic fracturing risks. In the funding bill for environment agencies for fiscal year 2010, Congress directed EPA to conduct a study on the relationship between hydraulic fracturing and drinking water. The EPA has announced that it will conduct a "comprehensive research study to investigate the potential adverse impact that hydraulic fracturing may have on water quality and public health."[570] The EPA has submitted a draft study plan to the agency's Science Advisory Board for review. The study plan includes more than just whether hydraulic fracturing chemicals find their way into drinking water near injection sites; the study plan currently proposes an analysis of the "full lifespan" of water used in hydraulic fracturing, from its acquisition, through its use, to its ultimate treatment and disposal.[571]

In addition to the EPA study, Congressmen Henry Waxman (D-CA) and Ed Markey (D-MA) launched an inquiry into hydraulic fracturing.[572] The two representatives requested information from eight oil and gas service companies regarding the chemicals used in fracturing fluids, stating that the purpose of the inquiry was to assess whether the practices "poses any environmental or public health risks that Congress should address." On April 18, 2011, Waxman, Market and Representative Diana De Gette released a report on the Chemicals Used in Hydraulic Fracturing, summarizing the results of the responses from various service providers.[573] In September 2010, EPA also issued information request to various hydraulic fracturing service providers, also seeking information on the chemical composition of fracturing fluids.

The hard look that fracing is now receiving is the latest in a long history of dispute and controversy over the regulation of hydraulic fracturing under the SDWA. Before litigation in 1997, the EPA had not regulated hydraulic fracturing under the SDWA and had believed that hydraulic fracturing was not intended to be regulated under the SDWA.[574] The dispute that changed the EPA's position started in 1994, when LEAF petitioned the EPA to withdraw the EPA's approval of Alabama's UIC program because it did not regulate hydraulic fracturing associated with coal bed methane production.[575] The EPA rejected LEAF's request and LEAF appealed the EPA's decision.[576]

In 1997, the Eleventh Circuit ruled on LEAF's appeal and concluded that hydraulic fracturing is included in the definition of 'underground injection.'[577] Alabama submitted a

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570 EPA Press Release, "EPA Initiates Hydraulic Fracturing Study: Agency seeks input from Science Advisory Board," March 18, 2010.

571 EPA Press Release, "EPA Submits Draft Hydraulic Fracturing Study Plan to Independent Scientists for Review," February 8, 2011.

572 "Waxman, Markey Launch Hydraulic-Fracturing Inquiry" E&E News, Feb. 18, 2010.

573 "Chemicals Used in Hydraulic Fracturing", United States House of Representatives, Committee on Energy and Commerce, Minority Staff, April 2011, http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf (last visited August 1, 2011).

574 65 Fed. Reg. 45774 (July 25, 2000).

575 *See* Legal Environmental Assistance Foundation, Inc. v. United State Environmental Protection Agency, 118 F.3d 1467, 1471 (11th Cir. 1997).

576 *Id*.

577 *Id*. at 1478.

revised UIC program to the EPA, and the EPA approved the program.[578] LEAF again appealed the EPA's approval of Alabama's program. In this second appeal, the EPA was successful and the court generally upheld Alabama's program.[579] The court remanded one issue to the EPA for consideration—the EPA's classification of the hydraulic fracturing as not a Class II injection well, and remanded the compliance of Alabama's program with the Class II well program requirements.[580]

Following the LEAF decisions, bills were introduced to reverse the cases' requirements that fracing be regulated under the SDWA. However, until 2005, with the enactment of the Energy Policy Act, discussed above, the legislation was not passed. In the interim, the EPA entered into a Memorandum of Agreement with three hydraulic fracturing companies under which those companies agreed to eliminate diesel from fracturing fluids in coalbed methane production wells.[581]

During this same time period, the EPA undertook a study of hydraulic fracturing and its impacts on drinking water sources.[582] This study involved a review of coalbed methane fracturing practices, literature review, and evaluation of reported instances of groundwater contamination from hydraulic fracturing operations. The EPA ultimately concluded that "the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs…."[583]

Whether further EPA regulations will apply to fracing appears to be a point of contention between some states and the federal government. For example, in a resolution passed by the 61st Legislative Assembly of North Dakota, the legislature specifically noted that the EPA has never interpreted hydraulic fracturing as constituting 'underground injection' under the Safe Drinking Water Act.[584] The North Dakota legislature further observed that "regulation of hydraulic fracturing as underground injection under the Safe Drinking Water Act would impose significant administrative costs on the state, substantially increase the cost of drilling oil and gas wells, and potentially stop the development of our state's valuable natural resources include the Bakken and other formations with no resulting environmental benefits."[585] Thus, North Dakota rejected the contention that its regulatory scheme does not adequately protect against the environmental threats allegedly associated with hydraulic fracturing, and the notion that hydraulic fracturing should be regulated as an underground injection. Lynn Helms, director of North Dakota's Department of Mineral Resources, stated in a House Energy and Mineral Resources Subcommittee hearing in June of 2009:

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578 *See* Legal Environmental Assistance Foundation, Inc. v. United States Environmental Protection Agency, 276 F.3d 1253, 1256 (11th Cir. 2001).

579 *Id*. at 1365.

580 *Id*. at 1264.

581 Memorandum of Agreement between the U.S. Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (Dec. 12, 2003).

582 Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, June 2004, United States Environmental Protection Agency.

583 *Id*. at ES-1.

584 S. Con. Res. 4020, 61st Leg., Reg. Sess. (N.D. 2009). Legislative history *available at* http://www.legis.nd.gov/assembly/61-2009/bill-actions/ba4020.html (last visited Apr. 6, 2010).

585 *Id*.

"As the head regulator of oil and natural gas development in the state of North Dakota and an officer of the IOGCC representing all oil and natural gas producing state regulators, I can assure you that we have no higher priority than the protection of our states' water resources. … It is my firmly held view and that of the IOGCC that the subject of hydraulic fracturing is adequately regulated by the states and needs no further study."[586]

Given that the EPA has never interpreted the injection of fracing fluids into a wellbore to be an 'underground injection' under the SDWA, and the increased costs with no resulting environmental benefit, it is likely that other states will also reject the argument that fracing comes within a regulatory scheme that addresses underground injection. However, a number of states have bifurcated coverage of environmental issues arising from oil and gas. A common arrangement, as seen above, is to have one state agency regulate oil and gas conservation and development, but to have limited environmental regulatory oversight, and to have a second state agency regulate environmental issues without considering oil and gas development except for downstream effects.

If there is a gap between the coverage of two such agencies wherein regulation of fracing operations (outside of common county and municipal ordinances, such as those governing noise and traffic control of production equipment) and the disposal of used fracing fluid falls, potential problems associated with fracing may go unaddressed. If such problems develop, the EPA or other agencies may attempt to step into this lacuna of regulatory coverage, imposing federal control of certain types of activities and disclosures.

In addition to commissioning the EPA study, in May of this year, the Obama Administration commissioned a study by the Department of Energy to make recommendations to improve the safety and environmental performance of natural gas hydraulic fracturing from shale formations.[587] This DOE study is in addition to its 2009 study on the subject.[588] On August 11, 2011, the DOE task force released a draft report that provided that natural gas exploration was an environmental risk if operators did not meet certain recommendations for water and air quality.[589]

As described above, case law reflects a hesitant judiciary, unsure which, if any, agency or legislative body controls fracing. Such gaps have caused federal-level politicians and environmentalists to call for federal regulation of fracing. Generally speaking, state regulators and industry players do not want such intrusion by federal agencies. In some cases, the potential for federal oversight may be dampened by increased state oversight. For example, in Pennsylvania, industry organizations such as the Marcellus Shale Coalition have supported the Pennsylvania DEP's significant increase of permit fees to fund the hire of more oil and gas

586 *See* IOGCC, "Hydraulic Fracturing" *supra* note 205.

587 *See* DOE, US DOE forms natural gas hydraulic fracturing safety panel, May 6, 2011, *available at* http://www.pennenergy.com/index/petroleum/display/0606207726/articles/pennenergy/petroleum/exploration/2011/05/us-doe_forms_natural.html (last visited August 9, 2011).

588 *See* DOE Primer, *supra* note 40.

589 This preliminary report is *available at* http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf (last visited Sep. 25, 2011).

inspectors.[590] Similar increases in the regulatory and enforcement powers of oil and gas and/or environmental agencies in other states would probably attenuate the current push for increased federal control.

Securities Exchange Commission

Fracing has caused another federal agency to stir. In response to the queries of a number of Congressmen, the Securities and Exchange Commission ("*SEC*") has apparently decided to investigate whether companies are reporting the financial viability of shale gas and oil development accurately. The SEC recently began serving subpoenas on companies engaged in shale gas.[591] Among other things, the subpoenas seek information regarding the performance of shale gas wells against forecasted or projected performance, the propriety of decline curves for the wells, and the calculation and public disclosure of full-cycle margins.

How many requests and the SEC's purpose in sending them are still unclear, but it is thought by some opponents of the natural gas industry that the subpoenas may reflect the SEC's interest in determining whether companies are misreporting how their gas wells perform and how much gas these companies can profitably extract over the lifetime of a particular field.[592]

These requests for information come on the heels of recent changes to the SEC's reserve reporting requirements, however, wherein the SEC expanded the type and categories of reserves that could be reported. SEC disclosures filed after December 31, 2009 must now comply with the SEC's Financial Reporting Release No. 78, Modernization of Oil and Gas Reporting (Release No. 33-8995), which provides the first major overhaul of oil and gas reporting requirements since their inception in 1978. The updated requirements follow the recommendations of the Petroleum Resources Management System of the Society of Petroleum Engineers. These changes added new rules to existing regulations and definitions in Rule 4-10(a) of Regulation S-X and to Subpart 1200 of Regulation S-K.

New Reserve Categories and Recovery Technologies. Many report issuers were pleased with the addition of the new categories of reserves and began reviewing their assets with an eye towards buttressing their "proved" reserves with large volumes of the new reserve types, which included shale gas reservoirs and other "unconventional" plays. As predicted,[593] some companies showed dramatically increased reserves, leading both to questions regarding the lack of clarity for some of the new regulations and scrutiny by the SEC. On October 26, 2009, the SEC released "Compliance and Disclosure Interpretations: Oil and Gas Rules" which set forth explanations of some of the new oil and gas rules in Regulation S-X and Regulation S-K in response to questions posed to the SEC's Division of Corporation Finance during the first half of 2009.

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590 *See* IOGCC, "Hydraulic Fracturing" *supra* note 205.

591 Ian Urbina, *Regulators Seek Records on Claims for Gas Wells*, N. Y. TIMES, July 29, 2011, available at http://www.nytimes.com/2011/07/30/us/30gas.html (last visited on Sep. 22, 2011).

592 *Id.*

593 William B. Nelson and Christopher Kulander, *The New Petroleum Reserve Categories and Valuation Requirements of the SEC*, OKLAHOMA BAR ASSOCIATION MINERAL LAW SECTION NEWSLETTER, Vol. XXX, No. 3, p. 9. (July, 2009).

In addition, using new disclosure rules regarding the use of reliable technology to determine "proved undeveloped reserves" ("*PUDs*"), some companies were able to increase the amount of PUDs booked, especially companies having large reserves of shale gas.[594] Under the new rules, the definition of proved undeveloped reserves has been changed to account for future changes in technology and to permit the classification of reserves as "proved" (or "probable" or "possible" reserves) even if they are not adjacent to existing wells.[595] In addition, while the SEC originally envisioned a five-year limit on classifying undeveloped reserves as proved, under the new rules companies will be able to include proved undeveloped reserves for longer than five years. They must, however, describe the circumstances that have or are expected to delay development, such as pipeline completion dates longer than five years from the time of the report.[596]

Energy companies also picked up that the SEC was intentionally vague when defining "reliable technology" as technology that has been tested to provide demonstrable and repeatable results. Not long after, real life examples of utilization of these new "reliable technologically" practices as approved by the SEC were provided by several companies. For example, in a recent issuance, Chesapeake Energy stated that it utilized and developed reliable geologic and engineering technology to book PUD reserves more than one location offsetting currently producing locations in the Barnett Shale and Fayetteville Shale in Texas and Arkansas without disclosing the specific technology employed.[597] Similarly, CNX Gas Corp. stated to the SEC that "[e]xtensions and discoveries also include 120,933 MMcfe [approximately 13.9% of PUDs as of Dec. 31, 2009] as a result of initially applying the amendments of [the new SEC reserve reporting rules] related to capturing proved undeveloped locations more than one location away if reliable technology can be demonstrated." Like Chesapeake, CNX did not describe in detail the reliable technology it utilized.

Unconventional Sources of Oil. Under the old SEC reporting rules, only conventional sources of reserves may be reported as proved reserves.[598] This definition explicitly excluded reporting of "unconventional" or "non-traditional" sources of oil and gas, such as "the extraction of hydrocarbons from shale, tar sands, or coal"—generally speaking, all sources whereby extraction is made by methods other than an oil or gas well.[599] The original definitions of "oil and gas producing activities" also expressly excluded specialized refining activities and extraction of oil and gas by steam.[600]

As time progressed past 1982, this rule blocked the booking of reserves from sources

594 Marc Fallidori and Jeff Dobbs, *Studies Show Further Guidance needed on Revised Oil and Gas Disclosure Rules*, OIL & GAS FINANCIAL JOURNAL, Dec. 1, 2010, available at http://www.ogfj.com/index/article-display/3482369705/articles/oil-gas-financial-journal/volume-7/issue-12/features/studies-show-further-guidance-needed-on-revised.html (last visited Sep. 22, 2011).

595 Undeveloped Oil and Gas Reserves, 74 Fed. Reg. 2158, 2165-2166 (Jan. 14, 2009).

596 *Id*.

597 Fallidori & Dodds, *supra* note [-].

598 17 CFR § 210.4-10.

599 17 CFR § 210.4-10(a)

600 *Id*.

such as oil and gas from shale or coal or oil tar sands.[601] The SEC recognized that these sources were becoming crucial global hydrocarbon reserves and that new technologies made the production of these unconventional traps of hydrocarbons economic and viable alternatives to traditional plays.[602] Evaluators and oil companies that provided comment to the SEC proposals had longed chaffed at the restraining old rules and all applauded the new allowances for "oil and gas producing activities" to include extraction from unconventional sources. The majority cited that inclusion of these reserves would flesh out a more complete profile of the asset portfolio of companies which specialize in such non-traditional sources. Because of this dissatisfaction, the SEC sought to move away from having the definition of "oil and gas producing activities" be tethered to specific activities but rather be focused on the final product.[603] Under the new rules approved by the SEC after public comments and hearings, disclosure of these shale gas reserves was approved.

Of course, the new SEC regulations both gave *and* took away reportable reserves. Rule 4-10(a) (31) (ii) of Regulation S-X provides that undeveloped locations can be classified as having reserves only if a "development plan" has been adopted such that the PUDs are to be developed within five (5) years. In response to a question about the timeframe of future development plans, the Division established that PUDs and other undeveloped locations cannot be carried on reserve reports for longer than five years except under rare circumstances. A reserve portfolio composed of such PUDs could therefore be subject to a significant write-down on or before the end of five (5) years. This rule forced other companies to remove PUDs that had been previously booked as PUDs. This is especially germane in circumstances where continuously rolling drilling moratoriums may push off development of previously-booked reserves permanently, such as in New York.

Air Quality Permitting and Controls

The fracing process can result in the emissions of air pollutants from engines associated with mobile, construction and pumping equipment on the surface, from the materials pumped into the well and from the resulting produced gases and liquids. Emissions may include products of combustion from engines or other combustion sources, particulate matter from construction and vehicle movement, and methane, volatile organic compounds and hydrogen sulfide from the well and the recovered liquids. Potential concerns under the federal and state clean air acts include permitting of stationary sources of emissions and the impact of the emissions.

<u>Permitting</u>

Federal and state permitting requirements of primary concern to a temporary operation such as fracing are the preconstruction permit requirements commonly known as new source review ("*NSR*"). In most cases, the state has the responsibility of issuing any required NSR permit. It is possible, however, that the federal EPA may have permitting authority in certain areas, including Indian tribal areas. Additionally, in some states NSR permitting authority is

601 *Id*.

602 Extraction of Bitumen and Other Non-traditional Resources. 74 Fed. Reg. 2158, 2163 (Jan. 14, 2009).

603 *Id*.

placed in city or county government in the larger urban areas.

Because NSR is a "preconstruction" requirement, the permit, if required, must be obtained prior to installing the equipment. NSR permitting requirements normally apply only to stationary sources. Consequently, direct emissions from mobile sources such as trucks usually are exempted from permit requirements. Most jurisdictions also either exempt or provide expedited permitting procedures for portable equipment that is used on a temporary basis. Therefore, the owner of the operation may not have to submit detailed information to an air quality regulatory agency for equipment used solely for fracing operations and removed after fracing is completed. If the fracing operation will use equipment, such as engines or storage tanks, that will continue to be used after the well is completed, it is more likely that a site specific NSR permit is required. It is important that the owner identify the permitting requirements prior to construction, and determine the expected emissions in order to identify what NSR provisions apply. Each state establishes its own NSR rules and these can vary significantly.

Control of Emissions

Emission controls may be set forth in rules or imposed by permit conditions in a case-by-case review. Some emission control requirements may apply regardless of location while others will vary dependent on the air quality in the location of the proposed project. The control requirements may specify a level of control, direct that work be performed in a certain manner, or set numerical emission limits for one or more pollutants.

Typical emission controls include measures to limit nitrogen oxides and other products of combustion from engines. The rules or permits may require flares or vapor recovery units to control volatile gaseous compounds from vents or storage tanks. EPA through its Natural Gas STAR program has identified Reduced Emission Completion ("*REC*") technologies to limit flow-back emissions, including methane, but these require that pipelines to the well be in place. REC technologies include equipment to separate gas and liquid hydrocarbons during flowback. Given the temporary nature of a fracing operation, the control requirements may be less than what is required for sources at the well after completion.

Emissions Impact Analysis

Regulatory agencies evaluate the impacts of emissions for both short term and long term effects. Given the temporary nature of a fracing operation, the short term impacts are likely to pose more significant concerns.

The most likely significant short-term concerns relate to odors from the recovered gases and produced liquids including hydrogen sulfide and various volatile organic compounds. Many jurisdictions regulate odors to prevent "nuisance" conditions–the interference with the normal use and enjoyment of property outside the boundaries of the well site. The materials recovered during fracing frequently are odorous in nature. If the well site is near areas where people live or work, those odors, if not sufficiently controlled, may result in complaints and the issuance of violations by regulatory authorities.

Another significant concern with short term emissions is the presence of hazardous or toxic air pollutants such as benzene, toluene, xylene, etc., present in the materials produced from the well. Although the greatest concern with these types of compounds is long-term exposures contributing to public health problems, emissions during fracing are additive to the emissions during operations after completion. Consequently, many regulatory authorities restrict the off-property concentrations of these compounds on a short-term basis either through specific limits in rules and permits or through guidelines of what is believed necessary to protect public health.

Additionally, emissions of nitrogen oxides, sulfur dioxide, carbon monoxide, particulate matter and volatile organic compounds are regulated to ensure that the National Ambient Air Quality Standards ("*NAAQS*")[604] established by the federal EPA are achieved and maintained. Some of these standards have averaging times as short as one-hour and the emissions during fracing would also contribute to longer averaging times. Historically, compliance with NAAQS largely has been a concern for urban areas. Shale gas development, such as the Barnett Shale area in Texas, is now occurring in or near urban areas. Additionally, monitoring is determining that many rural areas also have NAAQS concerns. EPA in the last twenty years has promulgated significantly more restrictive NAAQS and is required to review each NAAQS every five years to determine whether revisions are appropriate.

As noted, even though fracing is a temporary activity, the emissions do contribute to potential concerns over long-term exposures evaluated under NAAQS and other standards. In recent years a new air pollution concern, greenhouse gases ("*GHGs*") contributing to climate change, has come to the forefront of public debate. Emissions of methane, previously largely unregulated, are now increasingly regulated as it is one of the GHGs. Recent studies have asserted that fracing releases significant amounts of methane, and that shale gas production, including fracing, emits substantially more methane than conventional gas production.[605]

<u>Future Developments</u>

EPA has issued a 604 page package containing proposed air quality rules under the New Source Performance Standards ("*NSPS*") and National Emission Standards for Hazardous Air Pollutants ("*NESHAPS*") programs.[606] The proposal affects oil and gas operations. EPA has proposed the rules pursuant to a consent decree which requires that final action on the rules occur by February 28, 2012.

The proposed NSPS rules include operational requirements for "green completions" using REC technology at newly fractured natural gas wells and existing natural gas wells that are either fractured or re-fractured. The owner or operator of a gas well would have to provide at least 30 days advance notice to the regulatory agencies (usually EPA and the state agency) of a

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604 40 CFR Part 50.

605 Howarth, Santoro, and Ingraffea, *Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations* (on file with author).

606 *See* EPA, Standards of Performance for New Stationary Sources, *available at* http://epa.gov/airquality/oilandgas/pdfs/20110728proposal.pdf (last visited August 8, 2011).

planned completion or recompletion of a hydraulically fractured well. If gas cannot be collected at those wells, pit flaring would be required unless it would be a safety hazard. Only pit flaring would be required at exploratory or delineation wells. As proposed, the green completion requirements would be limited to the wellhead, well bore, casing, tubing and any conveyance used to vent gas to the atmosphere; ancillary equipment such as tanks, separators and dehydrators would not be subject to the green completion requirements. EPA estimates that over 20,000 completions and recompletions each year will be subject to the green completion requirements.

Conservancy Districts

Another source of regulation affecting fracing are river conservancy districts. These are hybrid state and federal agencies with jurisdiction over the drainage basin of a particular river. While all river conservancy districts vary in scope, mission, and powers, their primary mission is comprehensive planning, water supply allocation, and protection of water quality and instream use of the water resources of a particular river. They manage water use, flood projects and overall water quality.

To accomplish these missions, these entities have occasionally regulated commercial and industrial uses of, and activities affecting, the surface water in their watersheds. These entities are particularly powerful in eastern America where the water rights regime generally entitled everyone is to a portion of the water and the control regime determines who can do what related to water in that basin. Typically, they are operated by a board which includes one representative from each state that the river is in and a representative from Army Corps of Engineers, which is the source of the federal component.

An example of such a commission which has had an impact on fracing is the Delaware River Basin Commission ("DRBC"), which oversees that river in eastern Pennsylvania and portions of Delaware, New York and New Jersey. The DRBC required permits for gas extraction projects within their watershed by 2009. In 2010, that requirement was expanded to cover all exploratory wells, halting drilling in some areas. The DRBC has probably therefore been the most stringent in its control of fracturing and gas development within that watershed. For example, the DRBC has:

- Proposed new fracing regulations, acting almost as if it was a state agency;
- Required approval of water sources and use;
- Encouraged the use of pre-approved sources such as re-used frac fluids, treated waste water, or mine drainage;
- Established well pad requirements or changed them, in addition to requirements of the state rules; and
- Overseen the regulation of wastewater disposal.

Conclusions

Given the size of the potential reserves made available by fracing, the influence and capital of the producers of natural gas, the money made by the mineral owners in bonus and royalty, and the jobs and tax revenue that fracing make possible, widespread hydraulic fracturing will continue and the hunt for prospective shale oil and gas will proliferate. Some cities and counties—and perhaps even some states—will succeed in preventing fracing through the pressure of citizens' groups and environment organizations, but too many parties stand to gain too much from this technology for fracing to be entirely stopped.

From a jurisprudential standpoint, the biggest question that states will need to settle, probably through case law, is whether fracing that can be proven to cross property boundary lines and which facilitates draining of an unleased neighboring tract constitutes trespass. Case law in currently limited, but until now, the prevailing attitude seems to be that the rule of capture allows such drainage unless the owner of the drained tract can prove some kind of damages outside of lost ultimate recovery from his tract. Another question is whether fracing that enhances production for one tract, but is detrimental to ultimate recovery for an entire unit, will be found to run afoul of the conservation efforts of state agencies.

The lengthy discussion of state law herein, while complex in its sweep of differences from state to state, serves to highlight some basic patterns of state regulation of fracing. First, states are moving towards expressly including fracing under general statutes and regulations that cover all oil and gas exploration and development activities. Second, just as state regulatory agencies require drilling logs and data when producers bring in a well, similar logs and pressure test data from fracing are a growing target for disclosure requirements among state agencies. Third, perhaps responding to the concerns raised by surface owners and environmentalists, a growing number of states want the exact ingredients of fracing fluids disclosed in completion reports. Fourth, specific disposal regimens for fracing fluid that returns to the surface through the borehole are beginning to coalesce into law, focusing on the protection of existing surface and groundwater assets. Fifth, required replacement or remediation of contaminated surface or groundwater assets, already coming in Pennsylvania, will probably spread to other states.

The next five years will also likely see a gradual settlement made on what aspects of fracing regulation will be delegated from the state level down to the county and municipal level. As described above, county and municipal authorities have not been reticent to regulate fracing. Traffic control, noise abatement, and permitted hours of operation have all been claimed by local authorities as areas subject to local control.

This flurry of state and local activity may attenuate the interest of EPA in federal oversight of fracing. The authors believe that, in general, the chances of federal oversight of fracing will be diminished if, by the time of the release of the second EPA report, most of the states with shale gas and oil development will have passed or will then formulating robust regulatory schemes governing the use of fracing.